San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT

APR 15 2009

DOCKET	
08-AFC-10	
DATE	APR 15 2009
RECD.	APR 20 2009

Eileen Allen
California Energy Commission
1516 Ninth Street
Sacramento, CA 95814

Re: Notice of Preliminary Determination of Compliance (PDOC)
Facility: Northern California Power Agency (08-AFC-10)
Project Number: N-1083490

Dear Ms. Allen:

Enclosed for your review and comment is the District's preliminary determination of compliance (PDOC) for the installation of a 255 MW (nominal), natural gas-fired, combined-cycle, electric generation facility that will consist of a General Electric's (GE) natural gas-fired "Rapid Response" Frame 7FA (or equivalent) Combustion Turbine Generator equipped with dry-low NOx combustors rated at a combined heat input rate of 1,885.3 MMBtu/hr, a Heat Recovery Steam Generator equipped with natural gas direct-fired duct burners rated at a heat input rate of 222 MMBtu/hr, a Steam Turbine Generator, a seven-cell mechanical draft cooling tower system equipped with high efficiency drift eliminators, and a natural gas-fired 65 MMBtu/hr auxiliary boiler, at 12745 North Thornton Road, Lodi, California. The applicant is requesting that a Certificate of Conformity (COC) with the procedural requirements of 40 CFR Part 70 be issued with this project.

The notice of preliminary decision for this project will be published approximately three days from the date of this letter. Please submit your written comments on this project within the 30-day public comment period which begins on the date of publication of the public notice.

Thank you for your cooperation in this matter. If you have any questions regarding this matter, please contact Mr. Jagmeet Kahlon of Permit Services at (209) 557-6452.

Sincerely,

David Warner
Director of Permit Services

DW: JK/ry
Enclosures

Stockton Record

NOTICE OF PRELIMINARY DECISION
FOR THE PROPOSED ISSUANCE OF
DETERMINATION OF COMPLIANCE

NOTICE IS HEREBY GIVEN that the San Joaquin Valley Unified Air Pollution Control District solicits public comment on the proposed issuance of determination of compliance (DOC) to Northern California Power Agency for the installation of a 255 MW (nominal), natural gas-fired, combined-cycle, electric generation facility that will consist of a General Electric's (GE) natural gas-fired "Rapid Response" Frame 7FA (or equivalent) Combustion Turbine Generator equipped with dry-low NOx combustors rated at a combined heat input rate of 1,885.3 MMBtu/hr, a Heat Recovery Steam Generator equipped with natural gas direct-fired duct burners rated at a heat input rate of 222 MMBtu/hr, a Steam Turbine Generator, a seven-cell mechanical draft cooling tower system equipped with high efficiency drift eliminators, and a natural gas-fired 65 MMBtu/hr auxiliary boiler, at 12745 North Thornton Road, Lodi, California.

The analysis of the regulatory basis for these proposed actions, Project #N-1083490, is available for public inspection at the District office at the address below. Written comments on this project must be submitted within 30 days of the publication date of this notice to **DAVID WARNER, DIRECTOR OF PERMIT SERVICES, SAN JOAQUIN VALLEY UNIFIED AIR POLLUTION CONTROL DISTRICT, 4800 ENTERPRISE WAY, MODESTO, CA 95356.**

DETERMINATION OF COMPLIANCE EVALUATION

Northern California Power Agency (Lodi Energy Center)
California Energy Commission
Application for Certification Docket #: 08-AFC-10

Facility Name:	Northern California Power Agency
Mailing Address:	P.O. Box 1478 Lodi, CA 95241-1478
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Engineer:	Jagmeet Kahlon, Air Quality Engineer
Lead Engineer:	Rupi Gill, Permit Services Manager
Date:	February 4, 2009
District Project #:	N-1083490
Permit #:	N-2697-5-0, N-2697-6-0, N-2697-7-0
Submitted:	September 5, 2008
Deemed Complete:	October 2, 2008

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I. PROPOSAL

Northern California Power Agency (NCPA, a.k.a Lodi Energy Center) is requesting an Authority to Construct (ATC) for the installation of a 255 MW (nominal), natural gas-fired, combined-cycle, electric generation facility that will consist of a General Electric's (GE) natural gas-fired "Rapid Response" Frame 7FA (or equivalent) Combustion Turbine Generator (CTG) equipped with dry-low NOx (DLN) combustors rated at a combined heat input rate of 1,885.3 million British Thermal Units per hour (MMBtu/hr), a Heat Recovery Steam Generator (HRSG) equipped with natural gas direct-fired duct burners rated at a heat input rate of 222 MMBtu/hr, a Steam Turbine Generator (STG), a seven-cell mechanical draft cooling tower system equipped with high efficiency drift eliminators, a deaerating surface condenser to convert the steam from low-pressure section of the STG into water for re-use in HRSG feed water, and a natural gas-fired auxiliary boiler equipped with low NOx burner rated at a heat input rate of 65 MMBtu/hour for GE's "Rapid Response" system.

Exhaust from both CTG and HRSG duct burner will be vented through a Selective Catalytic Reduction (SCR) system for nitrogen oxide (NOx) emissions control, and through an oxidation catalyst to convert carbon monoxide (CO) into carbon dioxide (CO_2) gas.

NCPA has requested that the ATC should be issued with Certificate of Conformity (COC), which is EPA's 45-day review of the project prior to the issuance of the final ATC. This project will be published in the local newspaper (Stockton Record) for public review and comment. The public comment period will last 30-days from the date of publication.

NCPA has already submitted an Application for Certification (AFC) with the California Energy Commission (CEC). Currently, this project is going through the licensing process led by the CEC. Pursuant to SJVAPCD Rule 2201, Section 5.8, the District is required to submit a Determination of Compliance (DOC), which is this document, to the CEC within 240 days after acceptance of an application as complete. DOC is functionally equivalent to ATC provided that the CEC approves the AFC and certificate granted by the Commission includes all conditions of the DOC. CEC is the lead agency for determining California Environmental Quality Act (CEQA) requirements for this project.

NCPA had filed applications to obtain Prevention of Significant Deterioration (PSD) requirements from EPA Region 9.

II. APPLICABLE RULES

Rule 1080	Stack Monitoring (12/17/92)
Rule 1081	Source Sampling (12/16/93)
Rule 1100	Equipment Breakdown (12/17/92)

Rule 2010	Permits Required (12/17/92)
Rule 2201	New and Modified Stationary Source Review Rule (9/21/06)
Rule 2520	Federally Mandated Operating Permits (6/21/01)
Rule 2540	Acid Rain Program (11/13/97)
Rule 4001	New Source Performance Standards (4/14/99) 40 CFR Part 60 Subpart GG - Standards of Performance for Stationary Gas Turbines 40 CFR Part 60 Subpart KKKK – Standards of Performance for Stationary Combustion Turbines 40 CFR Part 60 Subpart Dc – Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units
Rule 4002	National Emissions Standards for Hazardous Air Pollutants (5/18/00)
Rule 4101	Visible Emissions (02/17/05)
Rule 4102	Nuisance (12/17/92)
Rule 4201	Particulate Matter Concentration (12/17/92)
Rule 4202	Particulate Matter Emission Rate (12/17/92)
Rule 4301	Fuel Burning Equipment (12/17/92)
Rule 4304	Equipment Tuning Procedure for Boilers, Steam Generators and Process Heaters (10/19/95)
Rule 4305	Boilers, Steam Generators and Process Heaters – Phase 2 (8/21/03)
Rule 4306	Boilers, Steam Generators and Process Heaters – Phase 3 (3/17/05)
Rule 4320	Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters greater than 5.0 MMBtu/hr (10/16/08)
Rule 4703	Stationary Gas Turbines (9/20/07)
Rule 4801	Sulfur Compounds (12/17/92)
Rule 7012	Hexavalent Chromium – Cooling Towers (12/17/92)
Rule 8011	General Requirements (8/19/04)
Rule 8021	Construction, Demolition, Excavation, Extraction and Other Earthmoving Activities (8/19/04)
Rule 8031	Bulk Materials (8/19/04)
Rule 8041	Carryout and Trackout (8/19/04)
Rule 8051	Open Areas (8/19/04)
Rule 8061	Paved and Unpaved Roads (8/19/04)
Rule 8071	Unpaved Vehicle/Equipment Traffic Areas (9/16/04)

California Health & Safety Code Section 41700 (Public Nuisance)
California Health & Safety Code Section 42301.6 (School Notice)
California Health & Safety Code Section 44300 (Air Toxic "Hot Spots")
Public Resources Code 21000-21177: California Environmental Quality Act (CEQA)
California Code of Regulations, Title 14, Division 6, Chapter 3, Sections 15000-15387: CEQA Guidelines
40 CFR Part 51 Appendix S Requirements for $PM_{2.5}$

III. PROJECT LOCATION

The proposed equipment will be located at 12745 North Thornton Road, Lodi, California. There is no K-12 school within 1,000 feet of this location. Therefore, school notice, under California Health & Safety Code 42301.6 is not required.

IV. PROCESS DESCRIPTION

GE's "Rapid Response" technology will be used to lower the emissions from CTG during the startup period. An auxiliary boiler will be used as part of "Rapid Response" package to pre-heat the CTG fuel and to provide STG sealing steam prior to the CTG startup. This technology lowers the startup period, thereby, lowers the startup emissions.

CTG combustion air will flow through the inlet air filters, evaporative cooler and associated air inlet ductwork, be compressed in the CTG compressor section, and then enter the CTG combustion section. Natural gas fuel will be injected into the compressed air in the combustion section and the mixture is ignited. The hot combustion gases will expand through the power turbine section of the CTG, causing the shaft to rotate that drives both the electrical generator and CTG compressor. The hot combustion gases will exit the turbine section and enter the HRSG with duct burners, where they will heat feedwater that will be pumped into the HRSG. The feedwater will be converted to superheated steam and delivered to the steam turbine at high pressure (HP), intermediate pressure (IP) and low pressure (LP). The use of multiple steam delivery pressures will permit an increase in cycle efficiency and flexibility. High pressure steam will be delivered to the HP section of the steam turbine, intermediate pressure steam will augment the reheat section of the HRSG and will deliver this steam to the IP section of the STG and LP steam will be injected at the beginning of the LP section of the steam turbine, and both flows (LP and IP) will expand in the LP steam turbine section. Steam leaving the LP section of the steam turbine will enter the deaerating surface condenser and transfer heat to circulating cooling water, which will condense the steam to water. The condensed water will be delivered to the HRSG feed water system. The condenser cooling water will circulate through a mechanical draft evaporative cooling tower, where the heat absorbed in the condenser will be rejected to the atmosphere.

Flue gases due to combustion of natural gas fuel in the CTG and the HRSG duct burners will be vented through an SCR system for NOx emissions control, and an oxidation catalyst for CO control.

CTG and HRSG can be operated 24 hours per day and 7 days a week. The facility will be frequently dispatched and will operate on the order of approximately a 76 to 82% annual capacity factor. The auxiliary boiler is expected to operate during CTG startup only.

CTG, HRSG duct burner, and the auxiliary boiler all will be operated exclusively on natural gas fuel.

V. EQUIPMENT LISTING

N-2697-5-0

255 MW (NOMINAL) COMBINED-CYCLE ELECTRIC GENERATION PLANT CONSISTING OF A GENERAL ELECTRIC INDUSTRIAL FRAME "RAPID RESPONSE" 7FA (OR EQUIVALENT) NATURAL GAS-FIRED TURBINE ENGINE WITH DRY LOW-NO_X COMBUSTORS, A HEAT RECOVERY STEAM GENERATOR EQUIPPED WITH 222 MMBTU/HOUR NATURAL GAS-FIRED DUCT BURNER SERVED BY A SELECTIVE CATALYTIC REDUCTION WITH AMMONIA INJECTION AND AN OXIDIZATION CATALYST AND A STEAM TURBINE GENERATOR

N-2697-6-0

60,000 GALLON/MIN COOLING TOWER WITH SEVEN CELLS SERVED BY HIGH EFFICIENCY DRIFT ELIMINATORS

N-2697-7-0

65 MMBTU/HR RENTECH BOILER SYSTEMS INC "D" TYPE BOILER EQUIPPED WITH A TODD/COEN RMB ULTRA LOW-NO_X BURNER (PART OF GE's "RAPID RESPONSE" SYSTEM)

VI. EMISSION CONTROL TECHNOLOGY EVALUATION

N-2697-5-0

NCPA has proposed to install a CTG with a DLN combustors, and HRSG with ultra-low NOx burners to control NOx formation. An SCR system with ammonia injection will also be utilized to reduce the NOx emissions. CO emissions will be controlled using an oxidation catalyst. Emission concentrations of less than or equal to 2.0 ppmvd NOx @ 15% O_2 on 1-hour average basis and less than or equal to 3 ppmvd CO @ 15% O_2 on 3-hour average basis are expected from this installation. Detailed discussion on NOx and CO formation and the emission control technique are explained in the following section:

NO_X is the major pollutant of concern when combusting natural gas. Virtually all gas turbine NO_X emissions originate as NO. This NO is further oxidized in the exhaust system or later in the atmosphere to form the more stable NO_2 molecule. There are two mechanisms by which NO_X is formed in turbine combustors: 1) the oxidation of atmospheric nitrogen found in the combustion air (thermal NO_X and prompt NO_X), and 2) the conversion of nitrogen chemically bound in the fuel (fuel NO_X).

Thermal NO_X is formed by a series of chemical reactions in which oxygen and nitrogen present in the combustion air dissociate and subsequently react to form oxides of nitrogen.

Prompt NO_X, a form of thermal NO_X, is formed in the proximity of the flame front as intermediate combustion products such as HCN, H, and NH are oxidized to form NO_X. Prompt NO_X is formed in both fuel-rich flame zones and dry low NO_X (DLN) combustion zones. The contribution of prompt NO_X to overall NO_X emissions is relatively small in conventional near-stoichiometric combustors, but this contribution is significant of overall thermal NO_X emissions in DLN combustors. For this reason prompt NO_X becomes an important consideration for DLN combustor designs, and establishes a minimum NO_X level attainable in lean mixtures.

Fuel NO_X is formed when fuels containing nitrogen are burned. Molecular nitrogen, present as N_2 in some natural gas, does not contribute significantly to fuel NO_X formation. With excess air, the degree of fuel NO_X formation is primarily a function of the nitrogen content in the fuel. When compared to thermal NO_X, fuel NO_X is not currently a major contributor to overall NO_X emissions from stationary gas turbines firing natural gas.

The level of NO_X formation in a gas turbine, and hence the NO_X emissions, is unique (by design factors) to each gas turbine model and operating mode. The primary factors that determine the amount of NO_X generated are the combustor design, the types of fuel being burned, ambient conditions, operating cycles, and the power output of the turbine.

The design of the combustor is the most important factor influencing the formation of NO_X. Design parameters controlling air/fuel ratio and the introduction of cooling air into the combustor strongly influence thermal NO_X formation. Thermal NO_X formation is primarily a function of flame temperature and residence time. The extent of fuel/air mixing prior to combustion also affects NO_X formation. Simultaneous mixing and combustion results in localized fuel-rich zones that yield high flame temperatures in which substantial thermal NO_X production takes place. Injecting water or steam into a conventional combustor provides a heat sink that effectively reduces peak flame temperature, thereby reducing thermal NO_X formation. Premixing air and fuel at a lean ratio approaching the lean flammability limit (approximately 50% excess air) significantly reduces peak flame temperature, resulting in minimum NO_X formation during combustion. This is known as dry low NO_X (DLN) combustion.

SCR systems selectively reduce NO_X emissions by injecting ammonia (NH_3) into the exhaust gas stream upstream of a catalyst. Nitrogen oxides, NH_3, and O_2 react on the surface of the catalyst to form molecular nitrogen (N_2) and H_2O. SCR is capable of over 90 percent NO_X reduction. Titanium oxide is the SCR catalyst material most commonly used, though vanadium pentoxide, noble metals, or zeolites are also used. The ideal operating temperature for a conventional SCR catalyst is 600 to 750°F. Exhaust gas temperatures greater than the upper limit (750°F) will cause NO_X and NH_3 to pass through the catalyst un-reacted. Ammonia slip will be limited to 10 ppmvd @ 15% O_2.

CO is formed during the combustion process due to incomplete oxidation of the carbon contained in the fuel. Carbon monoxide formation can be limited by ensuring complete and efficient combustion of the fuel. High combustion temperatures, adequate excess air and good air/fuel mixing during combustion minimize CO emissions. Therefore, lowering combustion temperatures and staging combustion to limit NO_X formation can result in increased CO emissions.

Oxidation catalyst uses a precious metal catalyst bed to convert carbon monoxide (CO) to carbon dioxide (CO_2). No reagents are used upstream of the catalyst.

The inlet air filters will remove particulate matter from the combustion air stream, reducing the amount of particulate matter emitted into the atmosphere.

The lube oil coalescer will result in the merging together of oil mist to form larger droplets. The larger droplets will return to the oil stream instead of being emitted.

Inlet air temperature and density directly affects turbine performance. Hotter and drier the inlet air temperature results in lower the efficiency of the turbine. Conversely, colder air improves the efficiency and reduces emissions by reducing the amount of fuel required to achieve the required turbine output. The inlet air cooler will allow the turbine to operate in a more efficient manner than it would without it. The increased efficiency will reduce the amount of fuel necessary to achieve the required power output. The reduction in fuel consumption will result in lower combustion contaminant emissions.

<u>N-2697-6-0</u>

NCPA has proposed to use high efficiency drift eliminators to reduce drift, which is fine mist of water droplets entrained in the warm air leaving the cooling tower. Drift is proposed to be less than or equal to 0.0005 percent of the circulating water flow with the use of high efficiency drift eliminators.

<u>N-2697-7-0</u>

NCPA has proposed to use low NOx burners in the auxiliary boiler. These burners will reduce NOx formation by producing lower flame temperatures (and longer flames) than conventional burners. Conventional burners thoroughly mix all the fuel and air in a single stage just prior to combustion, whereas low-NOx burners delay the mixing of fuel and air by introducing the fuel (or sometimes the air) in multiple stages. Generally, in the first combustion stage, the air-fuel mixture is fuel rich. In a fuel rich environment, all the oxygen will be consumed in reactions with the fuel, leaving no excess oxygen available to react with nitrogen to produce thermal NOx. In the secondary and tertiary stages, the combustion zone is maintained in a fuel-lean environment. The excess air in these stages helps to reduce the flame temperature so that the reaction between the excess oxygen with nitrogen is minimized.

Use of flue gas re-circulation can reduce nitrogen oxides (NOx) emissions by 60% to 70%. In an FGR system, a portion of the flue gas is re-circulated back to the inlet air. As flue gas is composed mainly of nitrogen and the products of combustion, it is much lower in oxygen than the inlet air and contains virtually no combustible hydrocarbons. Thus, flue gas is practically inert. The addition of an inert mass of gas to the combustion reaction serves to absorb heat without producing heat, thereby lowering the flame temperature. Since thermal NOx is formed by high flame temperatures, the lower flame temperatures produced by FGR serve to reduce thermal NOx.

VII. GENERAL CALCULATIONS

A. Assumptions

N-2697-5-0

1. Assumptions will be stated as they will be made.

N-2697-6-0

1. Only particulate matter emissions are associated from the operation of the cooling tower.
2. Other assumptions will be stated as they will be made.

N-2697-7-0

1. O_2 based F-factor for natural gas combustion is 8,578 dscf/MMBtu corrected to 60°F.
2. CO_2 based F-factor for natural gas combustion is 1,024.2 dscf/MMBtu corrected to 60°F.
3. Other assumptions will be stated, as they are made.

B. Emission Factors (EFs)

1. Pre-Project Emission Factors (EF1):

N-2697-5-0, '-6-0, '-7-0

These emission units are new to the facility. Therefore, EF1 does not exist.

2. Post-Project Emission Factors (EF2):

N-2697-5-0

NCPA has proposed to achieve the emission concentrations and hourly emission limits listed in the following table.

NOx Emission Limits		
Category	Concentrations	PE (lb/hour)
Gas Turbine, startups/shutdowns[1]	--	160 (max), 100 (avg)
Gas Turbine, Base[2]	2.0 ppmvd @ 15% O_2, (1-hour average)	13.64
Gas Turbine, Peak[3]		15.25
CO Emission Limits		
Category	Concentrations	PE (lb/hour)
Gas Turbine, startups/shutdowns	--	900
Gas Turbine, Base	3 ppmvd @ 15% O_2 based on 3-hour average	12.46
Gas Turbine, Peak		13.93
VOC Emission Limits		
Category	Concentrations	PE (lb/hour)
Gas Turbine, startups/shutdowns	--	16.00
Gas Turbine, Base	2.0 ppmvd @ 15% O_2, with duct firing 1.4 ppmvd @ 15% O_2, with no duct firing, both limit based on 3-hour average	3.33
Gas Turbine, Peak		5.32
NH_3 Emission Limits		
Category	Concentrations	PE (lb/hour)
Gas Turbine, startups/shutdowns	--	25.25
Gas Turbine, Base	10.0 ppmvd @ 15% O_2	25.25
Gas Turbine, Peak		28.23
PM_{10} Emission Limits		
Category	Concentrations	PE (lb/hour)
Gas Turbine, startups/shutdowns	--	9.00
Gas Turbine, Base	--	9.00
Gas Turbine, Peak		11.00
SO_x Emission Limits		
Category	Concentrations	PE (lb/hour)
Gas Turbine, startups/shutdowns	--	5.37
Gas Turbine, Base	--	5.37
Gas Turbine, Peak		6.00

1 "Gas Turbine, startups/shutdown" includes the maximum emissions during startup and shutdown period.
2 "Gas Turbine, Base" means the maximum emissions when the CTG is operated with <u>no duct firing.</u>
3 "Gas Turbine, Peak" means the maximum emissions when the CTG is operated with <u>duct firing</u>

N-2697-6-0

Cooling tower is a source of particulate matter emissions. These emissions depend on the coolant recirculation rate, drift rate, total dissolved solid concentrations and the density of the coolant. Emission factor is not established for the cooling tower.

N-2697-7-0

NCPA has proposed to achieve the following emission limits for a 65 MMBtu/hr natural gas-fired boiler during start-up, steady state and shutdown operations.

Pollutant	Emission Factors
NO_X	7.0 ppmvd @ 3% O_2
CO	50 ppmvd @ 3% O_2
VOC	10.0 ppmvd @ 3% O_2
PM_{10}	0.0076 lb/MMBtu
SO_X	0.00285 lb/MMBtu

C. Potential to Emit

1. Pre-Project Potential to Emit (PE1)

N-2697-5-0, '-6-0, '-7-0

These emission units are new to the Stationary Source. Therefore, no pre-project emissions exist at this point.

2. Post Project Potential to Emit (PE2)

N-2697-5-0

NCPA is expecting to complete the turbine commissioning activities within 28 days of the initial startup. The proposed maximum emissions during the commissioning period are summarized in the following table for each pollutant:

Pollutant	Hourly (lb/hr)	Daily (lb/day)	Commissioning Activity
NO_X	400.00	4,000.0	Steam Blows, Part Load Operation
CO	2,000.00	20,000.0	Steam Blows, Part Load Operation
VOC	16.00	160.0	Steam Blows, Part Load Operation
PM_{10}	11.00	108.0	Full load operation with and without duct firing
SO_X	6.00	70.1	Full load operation with duct firing and startup/shutdown

Potential NOx, CO and VOC emissions from CTG/HRSG system are proposed to be determined using the operating schedule given in the following table for each quarter (Q).

Operating Schedule (hours) for NO_x, CO, VOC Emissions Calculations					
Category	Daily	Q1	Q2	Q3	Q4
Gas Turbine, startups/shutdowns	6	142	142	76	108
Gas Turbine, Base	6	1,184	1,208	800	1,040
Gas Turbine, Peak	12	350	350	1,100	700

Potential emissions are calculated by multiplying the operating schedule with the proposed hourly emission limit for each category.

Potential NO_X Emissions							
Category	Hourly (lb/hour)	PE2 (lb/day)	Q1 (lb)	Q2 (lb)	Q3 (lb)	Q4 (lb)	PE2 (lb/year)
Gas Turbine, startups/shutdowns	100.00 160.00 (max)	600.0	14,200	14,200	7,600	10,800	46,800
Gas Turbine, Base	13.64	81.8	16,150	16,477	10,912	14,186	57,725
Gas Turbine, Peak	15.25	183.0	5,338	5,338	16,775	10,675	38,126
Total:		**864.8**	35,688	36,015	35,287	35,661	**142,651**
[1]Total (without startup/shutdowns):		**346.6**	--	--	--	--	--
Potential CO Emissions							
Category	Hourly (lb/hour)	PE2 (lb/day)	Q1 (lb)	Q2 (lb)	Q3 (lb)	Q4 (lb)	PE2 (lb/year)
Gas Turbine, startups/shutdowns	900.00	5,400.0	127,800	127,800	68,400	97,200	421,200
Gas Turbine, Base	12.46	74.8	14,753	15,052	9,968	12,958	52,731
Gas Turbine, Peak	13.93	167.2	4,876	4,876	15,323	9,751	34,826
Total:		**5,642.0**	147,429	147,728	93,691	119,909	**508,757**
[1]Total (without startup/shutdowns):		**316.8**	--	--	--	--	--
Potential VOC Emissions							
Category	Hourly (lb/hour)	PE2 (lb/day)	Q1 (lb)	Q2 (lb)	Q3 (lb)	Q4 (lb)	PE2 (lb/year)
Gas Turbine, startups/shutdowns	16.00	96.0	2,272	2,272	1,216	1,728	7,488
Gas Turbine, Base	3.33	20.0	3,943	4,023	2,664	3,463	14,093
Gas Turbine, Peak	5.32	63.8	1,862	1,862	5,852	3,724	13,300
Total:		**179.8**	8,077	8,157	9,732	8,915	**34,881**
[1]Total (without startup/shutdowns):		**103.8**	--	--	--	--	--

[1]Total = 2 (PE_{Base}) + PE_{Peak} since the turbine can be operated 12 hours (base) and 12 hours (peak) without any startup/shutdown activity

Potential NH_3, PM_{10} and SO_x emissions from the CTG/HRSG system are proposed to be calculated by keeping the "Peak" and "Startups/Shutdowns" hours constant (given in proposed operating schedule for NOx, CO and VOC emissions), and by re-calculating the "Base" load hours using the maximum hours in a given quarter. For instance, "Base" load hours for Q1 = 2,160 hour – (142 + 350) = 1,668 hours

Operating Schedule (hours) for SO_x, PM_{10}, NH_3 Emissions Calculations					
Category	Daily	Q1	Q2	Q3	Q4
Gas Turbine, startups/shutdowns	6	142	142	76	108
Gas Turbine, Base	6	1,668	1,692	1,032	1,400
Gas Turbine, Peak	12	350	350	1,100	700

Potential emissions are calculated by multiplying the operating schedule with the proposed hourly emission limit for each category.

Potential NH_3 Emissions							
Category	Hourly (lb/hour)	PE2 (lb/day)	Q1 (lb)	Q2 (lb)	Q3 (lb)	Q4 (lb)	PE2 (lb/year)
Gas Turbine, startups/shutdowns	25.25	151.5	3,586	3,586	1,919	2,727	11,818
Gas Turbine, Base	25.25	151.5	42,117	42,723	26,058	35,350	146,248
Gas Turbine, Peak	28.23	338.8	9,881	9,881	31,053	19,761	70,576
Total:		**641.8**	55,584	56,190	59,030	57,838	**228,642**
[1]Total (without startup/shutdowns):		**641.8**	--	--	--	--	**--**
Potential PM_{10} Emissions							
Category	Hourly (lb/hour)	PE2 (lb/day)	Q1 (lb)	Q2 (lb)	Q3 (lb)	Q4 (lb)	PE2 (lb/year)
Gas Turbine, startups/shutdowns	9.00	54.0	1,278	1,278	684	972	4,212
Gas Turbine, Base	9.00	54.0	15,012	15,228	9,288	12,600	52,128
Gas Turbine, Peak	11.00	132.0	3,850	3,850	12,100	7,700	27,500
Total:		**240.0**	20,140	20,356	22,072	21,272	**83,840**
[1]Total (without startup/shutdowns):		**240.0**	--	--	--	--	**--**
Potential SO_x Emissions							
Category	Hourly (lb/hour)	PE2 (lb/day)	Q1 (lb)	Q2 (lb)	Q3 (lb)	Q4 (lb)	PE2 (lb/year)
Gas Turbine, startups/shutdowns	5.37	32.2	763	763	408	580	2,514
Gas Turbine, Base	5.37	32.2	8,957	9,086	5,542	7,518	31,103
Gas Turbine, Peak	6.00	72.0	2,100	2,100	6,600	4,200	15,000
Total:		**136.4**	11,820	11,949	12,550	12,298	**48,617**
[1]Total (without startup/shutdowns):		**136.4**	--	--	--	--	**--**

[1]Total = 2 (PE_{Base}) + PE_{Peak} since the turbine can be operated 12 hours (base) and 12 hours (peak) without any startup/shutdown activity

N-2697-6-0

Per applicant,

Drift Rate: $5.0 \times 10^{-6} \dfrac{\text{lb - drift}}{\text{lb - coolant}}$

Total Dissolved Solids Content (TDS): $3{,}000 \times 10^{-6} \dfrac{\text{lb - TDS}}{\text{lb - drift}}$

$$PE2 = \left(60{,}000 \frac{\text{gal}}{\text{min}}\right)\left(60 \frac{\text{min}}{\text{hr}}; 1{,}440 \frac{\text{min}}{\text{day}}\right)\left(5.0 \times 10^{-6} \frac{\text{lb - drift}}{\text{lb - coolant}}\right)\left(8.34 \frac{\text{lb}}{\text{gal}}\right)\left(3{,}000 \times 10^{-6} \frac{\text{lb - TDS}}{\text{lb - drift}}\right)$$

$$= 0.45 \frac{\text{lb - TDS}}{\text{hr}}; 10.8 \frac{\text{lb - TDS}}{\text{day}}$$

Using worst-case operating scenario of 365 days a year, the annual emissions would be:

$$PE2 = \left(10.8 \frac{\text{lb - TDS}}{\text{day}}\right)\left(365 \frac{\text{days}}{\text{yr}}\right)$$

$$= 3{,}942 \frac{\text{lb - TDS}}{\text{yr}}$$

All total dissolved solids (TDS) are assumed to be emitted in the form of particulate matter of 10 microns or less in size. Therefore, the potential PM_{10} emissions would be:

$$PE2 = 0.45 \frac{\text{lb - PM}_{10}}{\text{hr}}; 10.8 \frac{\text{lb - PM}_{10}}{\text{day}}; 3{,}942 \frac{\text{lb - PM}_{10}}{\text{yr}};\ 985.5 \frac{\text{lb - PM}_{10}}{\text{Quarter}}$$

N-2697-7-0

The following equation is used to calculate potential NO_x, CO and VOC emissions from the auxiliary boiler:

$$PE2 = \frac{(\text{ppmvd})\left(\text{F} - \text{factor} \frac{\text{dscf}}{\text{MMBtu}}\right)\left(\text{MW} \frac{\text{lb}}{\text{lb} - \text{mol}}\right)\left(\frac{\text{MMBtu}}{\text{hour}}; \frac{\text{MMBtu}}{\text{day}}; \frac{\text{MMBtu}}{\text{Quarter}}\right)}{\left(\text{MSV} \frac{\text{dscf}}{\text{lb} - \text{mol}}\right)\left(10^6\right)\left(\frac{20.95 - 3}{20.95}\right)}$$

Where:

ppmvd	=	emission concentration @ 3% O_2
F-factor	=	8,578 ft^3-exhaust/MMBtu @ 60 °F
MW	=	46 for NO_x
	=	28 for CO
	=	16 for VOC
MSV	=	379.5 ft^3/mol (Molar Specific Volume of Ideal Gas @ 60 °F)

NCPA has proposed to use the following heat input rates for the auxiliary boiler.

Heat Input Rate					
Hour (MMBtu/hour)	Daily (MMBtu/day)	Q1 (MMBtu)	Q2 (MMBtu)	Q3 (MMBtu)	Q4 (MMBtu)
65	780	9,230	9,230	4,940	7,020

<u>NO_x</u>

$$PE2 = \frac{(7.0)\left(8{,}578\frac{dscf}{MMBtu}\right)\left(46\frac{lb}{lb-mol}\right)\left(65\frac{MMBtu}{hour};780\frac{MMBtu}{day}\right)}{\left(379.5\frac{dscf}{lb-mol}\right)(10^6)\left(\frac{20.95-3}{20.95}\right)}$$

$$= 0.55\frac{lb-NO_x}{hour};6.6\frac{lb-NO_x}{day}$$

Similarly, heat input during each quarter results in the following emissions:

$$PE2_{Q1} = 78\frac{lb-NO_x}{Quarter}$$

$$PE2_{Q2} = 78\frac{lb-NO_x}{Quarter}$$

$$PE2_{Q3} = 42\frac{lb-NO_x}{Quarter}$$

$$PE2_{Q4} = 60\frac{lb-NO_x}{Quarter}$$

CO

$$PE2 = \frac{(50)\left(8{,}578\frac{dscf}{MMBtu}\right)\left(28\frac{lb}{lb-mol}\right)\left(65\frac{MMBtu}{hour};780\frac{MMBtu}{day}\right)}{\left(379.5\frac{dscf}{lb-mol}\right)\left(10^6\right)\left(\frac{20.95-3}{20.95}\right)}$$

$$= 2.40\frac{lb-CO}{hour};28.8\frac{lb-CO}{day}$$

Similarly, heat input during each quarter results in the following emissions:

$$PE2_{Q1} = 341\frac{lb-CO}{Quarter}$$

$$PE2_{Q2} = 341\frac{lb-CO}{Quarter}$$

$$PE2_{Q3} = 182\frac{lb-CO}{Quarter}$$

$$PE2_{Q4} = 259\frac{lb-CO}{Quarter}$$

VOC

$$PE2 = \frac{(10.0)\left(8{,}578\frac{dscf}{MMBtu}\right)\left(16\frac{lb}{lb-mol}\right)\left(65\frac{MMBtu}{hour};780\frac{MMBtu}{day}\right)}{\left(379.5\frac{dscf}{lb-mol}\right)\left(10^6\right)\left(\frac{20.95-3}{20.95}\right)}$$

$$= 0.27\frac{lb-VOC}{hour};3.3\frac{lb-VOC}{day}$$

Similarly, heat input during each quarter results in the following emissions:

$$PE2_{Q1} = 39\frac{lb-VOC}{Quarter}$$

$$PE2_{Q2} = 39\frac{lb-VOC}{Quarter}$$

$$PE2_{Q3} = 21\frac{lb-VOC}{Quarter}$$

$$PE2_{Q4} = 30\frac{lb-VOC}{Quarter}$$

<u>PM_{10}</u>

$$PE2 = \left(0.0076\frac{lb}{MMBtu}\right)\left(65\frac{MMBtu}{hour};780\frac{MMBtu}{day}\right)$$
$$= 0.49\frac{lb\text{-}PM_{10}}{hour};5.9\frac{lb\text{-}PM_{10}}{day}$$

Similarly, heat input during each quarter results in the following emissions:

$$PE2_{Q1} = 70\frac{lb-PM_{10}}{Quarter}$$

$$PE2_{Q2} = 70\frac{lb-PM_{10}}{Quarter}$$

$$PE2_{Q3} = 38\frac{lb-PM_{10}}{Quarter}$$

$$PE2_{Q4} = 53\frac{lb-PM_{10}}{Quarter}$$

<u>SO_x</u>

$$PE2 = \left(0.00285\frac{lb}{MMBtu}\right)\left(65\frac{MMBtu}{hour};780\frac{MMBtu}{day}\right)$$
$$= 0.19\frac{lb\text{-}SO_x}{hour};2.2\frac{lb\text{-}SO_x}{day}$$

Similarly, heat input during each quarter results in the following emissions:

$$PE2_{Q1} = 26\frac{lb-SO_x}{Quarter}$$

$$PE2_{Q2} = 26 \frac{lb - SO_x}{Quarter}$$

$$PE2_{Q3} = 14 \frac{lb - SO_x}{Quarter}$$

$$PE2_{Q4} = 20 \frac{lb - SO_x}{Quarter}$$

Summary:

Pollutant	Hourly (lb/hour)	PE2 (lb/day)	Q1 (lb)	Q2 (lb)	Q3 (lb)	Q4 (lb)	PE2 (lb/year)
NOx	0.55	**6.6**	78	78	42	60	**258**
CO	2.40	**28.8**	341	341	182	259	**1,123**
VOC	0.27	**3.3**	39	39	21	30	**129**
PM_{10}	0.49	**5.9**	70	70	38	53	**231**
SO_x	0.19	**2.2**	26	26	14	20	**86**

3. Adjusted increase in Permitted Emissions (AIPE) Calculations

AIPE is used to determine if BACT is required for emission units that are being modified. The proposed units are new emission units. Therefore, AIPE calculations are not necessary.

D. Facility Emissions

1. Pre-Project Stationary Source Potential to Emit (SSPE1)

Pursuant to Section 4.9 of District Rule 2201, SSPE1 is the Potential to Emit from all units with valid Authorities to Construct (ATC) or Permits to Operate (PTO) at the Stationary Source and the quantity of emission reduction credits (ERCs) which have been banked since September 19, 1991 for Actual Emissions Reductions (AERs) that have occurred at the source, and which have not been used on-site. Please refer to Attachment H of this document for potential emission calculations for permit units N-2697-1 and N-2697-4.

SSPE1 (lb/yr)						
Permit #	**Type of Unit**	**NO_x**	**CO**	**VOC**	**PM_{10}**	**SOx**
N-2697-1-3	GE's LM-5000, 49 MW Electric Generator	40,880	117,530	51,830	17,520	11,571
N-2697-4-2	240 bhp, diesel- fueled emergency fire pump IC engine	97	23	7	4	0
ERC		0	0	0	0	0
Total		40,977	117,553	51,837	17,524	11,571
Major Source Thresholds		50,000	200,000	50,000	140,000	140,000
Major Source?		No	No	**Yes**	No	No

2. Post Project Stationary Source Potential to Emit (SSPE2)

Pursuant to Section 4.10 of District Rule 2201, the Post-Project Stationary Source Potential to Emit (SSPE2) is the Potential to Emit (PE) from all units with valid Authorities to Construct (ATC) or Permits to Operate (PTO) at the Stationary Source and the quantity of emission reduction credits (ERC) which have been banked since September 19, 1991 for Actual Emissions Reductions that have occurred at the source, and which have not been used on-site.

SSPE2 (lb/yr)						
Permit #	**Type of Unit**	**NO_x**	**CO**	**VOC**	**PM_{10}**	**SOx**
N-2697-1-3	GE's LM-5000, 49 MW Electric Generator	40,880	117,530	51,830	17,520	11,571
N-2697-4-2	240 bhp, diesel-fueled emergency fire pump IC engine	97	23	7	4	0
N-2697-5-0	**Combined cycle 255 MW Power Plant**	**142,651**	**508,757**	**34,881**	**83,840**	**48,617**
N-2697-6-0	**Cooling Tower**	**0**	**0**	**0**	**3,942**	**0**
N-2697-7-0	**65 MMBtu/hr, Auxiliary Boiler**	**258**	**1,123**	**129**	**231**	**86**
ERC		0	0	0	0	0
Total		183,886	627,433	86,847	105,537	60,274
Major Source Thresholds		50,000	200,000	50,000	140,000	140,000
Major Source?		**Yes**	**Yes**	**Yes**	No	No

3. Stationary Source Increase in Permitted Emissions (SSIPE)

It is a District Practice to define the SSIPE as the difference of SSPE2 and SSPE1. Negative SSIPE is equated to zero. SSIPE is summarized in the following table:

Pollutant	SSPE2 (lb/year)	SSPE1 (lb/year)	SSIPE (lb/year)
NO_x	183,886	40,977	142,909
CO	627,433	117,553	509,880
VOC	86,847	51,837	35,010
PM_{10}	105,537	17,524	88,013
SO_x	60,274	11,571	48,703

4. District Major Modification

The purpose of Major Modification calculations is to determine the following:

A. If Best Available Control Technology (BACT) is triggered for a new or modified emission unit that results in a Major Modification (District Rule 2201, §4.1.3); and

B. If a public notification is triggered (District Rule 2201, §5.4.1).

Per section VII.D.2 of this document, this facility is a Major Source for NOx, CO and VOC emissions. To determine if a project triggers a Major Modification, Net Emissions Increase (NEI) is calculated for each pollutant, and is compared with the Major Modification threshold limit for each pollutant. Since the San Joaquin Valley is in attainment for CO, NEI calculations for CO are not necessary.

NEI can be calculated as the sum of the difference of post-project potential emissions (PE2) and historical emissions (HE) for the emissions unit involved in this project. HE for the emission units involved in this project is zero. Thus,

<u>NO_x</u>

Permit	PE2 (lb/yr)	HE (lb/yr)	NEI = PE2- HE (lb/yr)	Major Modification Thresholds (lb/yr)	Major Modification?
N-2697-5-0	142,651	0	142,651	50,000	Yes
N-2697-6-0	0	0	0		
N-2697-7-0	258	0	258		
		Total:	142,909		

<u>VOC</u>

Permit	PE2 (lb/yr)	HE (lb/yr)	NEI = PE2- HE (lb/yr)	Major Modification Thresholds (lb/yr)	Major Modification?
N-2697-5-0	34,881	0	34,881	50,000	No
N-2697-6-0	0	0	0		
N-2697-7-0	129	0	129		
		Total:	35,010		

5. Federal Major Modification

The purpose of Federal Major Modification calculations is to determine the following:

A. If a Rule-compliance project qualifies for District Rule 2201's Best Available Control Technology (BACT) and offset exemptions (District Rule 2201, §4.2.3.5); and

B. If an Alternate Siting analysis must be performed (District Rule 2201, §4.15.1);

C. If the applicant must provide certification that all California stationary sources owned, operated, or controlled by the applicant that are subject to emission limits are in compliance with those limits or are on a schedule for compliance with all applicable emission limits and standards; and

D. If a public notification is triggered. (District Rule 2201, §5.4.1) Although the language in §5.4.1 states "Major Modifications", the District is taking a conservative approach by assuming this applies to both District Rule 2201 Major Modifications and Federal Major Modifications.

Per section VII.D.4 of this document, this project is a Major Modification for NOx emissions. To determine if it would be a Federal Major Modification, Net Emissions Increase (NEI) is calculated for NOx, and is compared with the Significance Threshold level of 50,000 lb/year for NOx.

NEI can be calculated as the sum of the difference of project actual emissions (PAE) and Baseline Actual Emissions (BAE). BAE for the emission units involved in this project is zero. Thus,

Permit	PAE (lb/yr)	BAE (lb/yr)	NEI = PE2- HE (lb/yr)	Significance Thresholds (lb/yr)	Federal Major Modification?
N-2697-5-0	142,651	0	142,651	50,000	Yes
N-2697-6-0	0	0	0		
N-2697-7-0	258	0	258		
		Total:	142,909		

VIII. COMPLIANCE

Rule 1080 Stack Monitoring

This rule grants the APCO the authority to request the installation, use, maintenance, and inspection of continuous emissions monitors (CEMs), and specifies performance standards for the equipment and administrative requirements for recordkeeping, reporting, and notification.

N-2697-5-0

NCPA has proposed to monitor NOx, CO and O_2 concentrations from the gas turbine system using CEMs to meet the requirements of applicable District rules and Federal regulations. Therefore, the following conditions will be placed to ensure compliance with the requirements of this rule.

- The owner or operator shall install, certify, maintain, operate, and quality-assure a continuous emission monitor system (CEMS) which continuously measures and records the exhaust gas NOx, CO, and O2 concentrations. Continuous emissions monitors shall be capable of monitoring emissions during normal operating conditions and during startups and shutdowns, provided that CEMS passes the relative accuracy requirement listed in 40 CFR Part 60, Appendix B, Performance Specification 2 (PS-2). If relative accuracy of CEMS cannot be demonstrated during the startup, CEMS results during startup and shutdown events shall be replaced with startup emission rates obtained from the source test to determine compliance with emission limits contained in this document. [District Rules 1080, 2201 and 4703, 40 CFR 60.4340(b)(1) and 40 CFR 60.4345(a)]

- The CEMS shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour or shall meet equivalent specifications established by mutual agreement of the District, the CARB and the EPA. [District Rule 1080 and 40 CFR 60.4345(b)]

- The NO_X, CO and O_2 CEMS shall meet the requirements in 40 CFR 60, Appendix F Procedure 1 and Part 60, Appendix B Performance Specification 2 (PS 2), or shall meet equivalent specifications established by mutual agreement of the District, the CARB, and the EPA. [District Rule 1080 and 40 CFR 60.4345(a)]

- In accordance with 40 CFR Part 60, Appendix F, 5.1, each CEMS must be audited at least once each calendar quarter. CEMS audit is not required for the quarters in which both relative accuracy test audit (RATA) and source testing are performed. The District shall be notified prior to completion of the audits. Audit reports shall be submitted along with quarterly compliance reports to the District. [District Rule 1080]

- The owner/operator shall perform a RATA for NO_X, CO and O_2 as specified by 40 CFR Part 60, Appendix F, 5.1.1, at least once every four calendar quarters. The permittee shall comply with the applicable requirements for quality assurance testing and maintenance of the continuous emission monitor equipment in accordance with the procedures and guidance specified in 40 CFR Part 60, Appendix F. [District Rule 1080]

- APCO or an authorized representative shall be allowed to inspect, as determined to be necessary, the required monitoring devices to ensure that such devices are functioning properly. [District Rule 1080]

- The CEMS data shall be reduced to hourly averages as specified in 40 CFR 60.13(h) and in accordance with 40 CFR 60.4350, or by other methods deemed equivalent by mutual agreement with the District, the CARB, and the EPA. [District Rule 1080 and 40 CFR 60.4350]

- Upon written notice from the District, the owner or operator shall provide a summary of the data obtained from the CEMS. This summary shall be in the form and the manner prescribed by the District. [District Rule 1080]

- The facility shall install and maintain equipment, facilities, and systems compatible with the District's CEMS data polling software system and shall make CEMS data available to the District's automated polling system on a daily basis. Upon notice by the District that the facility's CEMS is not providing polling data, the facility may continue to operate without providing automated data for a maximum of 30 days per calendar year provided the CEMS data is sent to the District by a District-approved alternative method. [District Rule 1080]

- The permittee shall maintain the following records: the date, time and duration of any malfunction of the continuous monitoring equipment; dates of performance testing; dates of evaluations, calibrations, checks, and adjustments of the continuous monitoring equipment; date and time period which a continuous monitoring system or monitoring device was inoperative. [District Rules 1080 and 2201 and 40 CFR 60.8(d)]

- The owner or operator shall submit a written report of CEM operations for each calendar quarter to the District. The report is due on the 30th day following the end of the calendar quarter and shall include the following: Time intervals, data and magnitude of excess NOx emissions, nature and the cause of excess (if known), corrective actions taken and preventive measures adopted; Averaging period used for data reporting corresponding to the averaging period specified in the emission test period used to determine compliance with an emission standard; Applicable time and date of each period during which the CEM was inoperative, except for zero and span checks, and the nature of system repairs and adjustments; A negative declaration when no excess emissions occurred. [District Rule 1080 and 40 CFR 60.4375(a) and 60.4395]

<u>N-2697-6-0</u>

NCPA is not required to install CEMs for this unit.

<u>N-2697-7-0</u>

NCPA has proposed to use a portable monitor that meet the District specifications (per District Policy SSP-1105 (4/28/08)) to monitor NOx, CO and O_2 concentrations on monthly basis. The permit conditions related to the monitoring methodology are discussed under Rule 4306.

Rule 1081 Source Sampling

This Rule requires adequate and safe sampling facilities such as sampling ports, sampling platforms, access to the sampling platforms for use in sampling to determine compliance with emissions limits, and specifies methods and procedures for source testing and sample collection.

N-2697-5-0

The following conditions will be placed to ensure compliance with the requirements of this rule.

- The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, CO, and O2 analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Emission Monitoring and Testing. [District Rule 1081]

- Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]

- Source testing shall be witnessed or authorized by District personnel and samples shall be collected by a California Air Resources Board (CARB) certified testing laboratory or a CARB certified source testing firm. [District Rule 1081]

- The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

N-2697-6-0

NCPA will be required to perform a blowdown water sample analysis on quarterly basis to determine compliance with the daily emission limit.

N-2697-7-0

The following conditions will be placed to ensure compliance with the requirements of this rule.

- The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, CO, and O2 analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Emission Monitoring and Testing. [District Rule 1081]

- Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]

- Source testing shall be witnessed or authorized by District personnel and samples shall be collected by a California Air Resources Board (CARB) certified testing laboratory or a CARB certified source testing firm. [District Rule 1081]

- The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

Compliance is expected with this Rule.

Rule 1100 Equipment Breakdown

This Rule defines a breakdown condition and the procedures to follow if one occurs. The corrective action, the issuance of an emergency variance, and the reporting requirements are also specified.

<u>N-2697-5-0, '-6-0, '-7-0</u>

The following conditions will be placed to ensure compliance with the requirements of this rule.

- The owner or operator shall notify the District of any breakdown condition as soon as reasonably possible, but no later than one hour after its detection, unless the owner or operator demonstrates to the District's satisfaction that the longer reporting period was necessary. [District Rule 1100]

- The District shall be notified in writing within ten days following the correction of any breakdown condition. The breakdown notification shall include a description of the equipment malfunction or failure, the date and cause of the initial failure, the estimated emissions in excess of those allowed, and the methods utilized to restore normal operations. [District Rule 1100]

Compliance is expected with this Rule.

Rule 2010 Permits Required

This Rule requires any person building, altering, or replacing any operation, article, machine, equipment, or other contrivance, the use of which may cause the issuance of air contaminants, to first obtain authorization from the District in the form of an ATC. By the submission of an ATC application, NCPA is complying with the requirements of this Rule.

Rule 2201 New and Modified Stationary Source Review Rule

1. Best Available Control Technology (BACT)

BACT requirements shall be triggered on a pollutant-by-pollutant basis and on an emissions unit-by-emissions unit basis. Unless exempted pursuant to Section 4.2, BACT shall be required for the following actions:

- Any new emissions unit or relocation from one Stationary Source to another of an existing emissions unit with a Potential to Emit (PE2) exceeding 2.0 pounds in any one day;

- Modifications to an existing emissions unit with a valid Permit to Operate resulting in an Adjusted Increase in Permitted Emissions (AIPE) exceeding 2.0 pounds in any one day;

- Any new or modified emissions unit, in a stationary source project, which results in a Major Modification, as defined in this rule

<u>N-2697-5-0</u>

Per section VII.C.2 of this document, PE2 is greater than 2.0 lb/day for NOx, SOx, PM_{10}, CO and VOC emissions. CO emissions from the entire facility are greater than 200,000 lb/year. Therefore, BACT is triggered for each pollutant.

BACT Guideline 3.4.2 is referenced to determine the BACT for each pollutant. Detailed Top-Down BACT Analysis for each pollutant is presented in Attachment E of this document. Summary of BACT requirements is explained briefly in the following the following section.

NOx

The above referenced guideline lists 2.5 ppmvd @ 15% O_2 (1-hour average) as achieved-in-practice, and 2.0 ppmvd @ 15% O_2 (1-hour average) as technologically feasible options.

NCPA has proposed to meet 2.0 ppmvd @ 15% O_2 on 1-hour average period. Therefore, this unit satisfies the District BACT requirements for NOx emissions.

CO

The above referenced guideline lists 6.0 ppmvd @ 15% O_2 as achieved-in-practice, and 4.0 ppmvd @ 15% O_2 (1-hour average) as technologically feasible options.

NCPA has proposed to meet 3.0 ppmvd @ 15% O_2 on 3-hour average period. Therefore, this unit satisfies the District BACT requirements for CO emissions.

VOC

The above referenced guideline lists 2.0 ppmvd @ 15% O_2 as achieved-in-practice, and 1.5 ppmvd @ 15% O_2 as technologically feasible options. Please note that 1.5 ppmvd @ 15% O2 (technologically feasible option) was added to the BACT guideline while processing Aera Energy's project S-1000170 in year 2000. Aera's project was never constructed. BACT analysis prepared for Aera's project was reviewed and it does not clearly indicate if the VOC concentrations (referenced as methane) of 1.5 ppmvd @ 15% O_2 was guaranteed with duct firing or with no duct firing. Moreover, recently processed permit C-3953-10 for Avenal Power Center contains emission limits of 2.0 ppmvd @ 15% O_2 with duct firing and 1.4 ppmvd @ 15% O_2 with no duct firing for VOC emissions. Therefore, the District considers these limits to be the BACT at this time without performing a cost-analysis for the technologically feasible option.

NCPA has proposed to meet 2.0 ppmvd @ 15% O_2 on 3-hour average period with duct firing, and 1.4 ppmvd @ 15% O2 on 3-hour average period with no duct firing. Therefore, this unit satisfies the District BACT requirements for VOC emissions.

PM_{10}

The above referenced guideline lists the use of air inlet filter cooler, lube oil vent coalescer and natural gas fuel to minimize the PM_{10} emissions.

Both CTG and duct burners will be exclusively fired on natural gas. CTG will have air inlet filter cooler and lube oil vent coalescer. Therefore, this unit satisfies the District BACT requirements for PM_{10} emissions.

SOx

The above referenced guideline lists PUC-regulated natural gas, or non-PUC regulated gas with no more than 0.75 grains-S/100 dscf, or equal.

NCPA has proposed to use PUC-regulated natural gas. Therefore, this unit satisfies the District BACT requirements for SOx emissions.

N-2697-6-0

Per section VII.C.2 of this document, potential emissions exceed 2.0 lb/day for PM_{10} emissions. Thus, BACT requirements are triggered for the cooling tower system.

BACT Guideline 8.3.10 lists the use of drift eliminators as technologically feasible option. Detailed Top-Down BACT Analysis for each pollutant is presented in Attachment E of this document.

NCPA has proposed to use high efficiency drift eliminators for the cooling tower. Therefore, this unit satisfies the District BACT requirements.

N-2697-7-0

Per section VII.C.2 of this document, PE2 for each criteria pollutant (NOx, SOx, PM_{10}, CO and VOC) exceed 2.0 lb/day. CO emissions from the entire facility are greater than 200,000 lb/yr. Thus, BACT is triggered for NOx, SOx, PM_{10}, CO and VOC emissions.

BACT Guideline 1.1.2 is referenced to address the requirements for each pollutant. Detailed Top-Down BACT Analysis for each pollutant is presented in Attachment E of this document. NCPA has proposed the following emission limits or control techniques:

NO_x:	7.0 ppmvd @ 3% O_2
SOx, PM_{10}, VOC:	operate boiler on natural gas fuel

Thus, BACT requirements are satisfied.

2. Offsets

Offsets are examined on a pollutant-by-pollutant basis, and are triggered for any pollutant with a SSPE2 equal to or greater than the threshold listed in following table.

Pollutant	SSPE1 (lb/yr)	SSPE2 (lb/yr)	Offset Thresholds (lb/yr)	Offset Triggered?
NO_x	40,977	183,886	20,000	Yes
CO	117,553	627,433	200,000	Yes
VOC	51,837	86,847	20,000	Yes
PM_{10}	17,524	105,537	29,200	Yes
SO_x	11,571	60,274	54,750	Yes

Offset Calculations

Section 4.7.1 states that for pollutants with SSPE1 greater than the emission offset threshold levels, emission offsets shall be provided for all increases in Stationary Source emissions, calculated as the differences of post-project Potential to Emit (PE2) and the Baseline Emissions (BE) of all new and modified emissions units, plus all increases in Cargo Carrier emissions. Thus,

EOQ = Σ(PE2 – BE) + ICCE, where

PE2 = Post-Project Potential to Emit (lb/yr)
BE = Baseline Emissions (lb/yr)
ICCE = Increase in Cargo Carrier emissions (lb/yr)

Section 4.7.2 states that for pollutants with SSPE1 less than or equal to the offset threshold levels, emission offsets shall be provided for all increases in Stationary Source emissions above the offset trigger levels, calculated as the difference of SSPE2 (lb/yr) and the offset trigger level (lb/yr), plus all increases in Cargo Carrier emissions (lb/yr). Thus,

EOQ = (SSPE2 – Offset Threshold Level) + ICCE, where

EOQ = Emissions Offset Quantity (lb/yr)
ICCE = Increase in Cargo Carrier emissions (lb/yr)

NOx

SSPE1 for NOx is greater than its respective Offset Threshold level. There is no increase in Cargo Carrier emissions from this project. BE is equal to zero for each emission unit. Thus,

EOQ = ΣPE2

Category	Q1	Q2	Q3	Q4
N-2697-5-0	35,688	36,015	35,287	35,661
N-2697-6-0	0	0	0	0
N-2697-7-0	78	78	42	60
EOQ (lb)	35,766	36,093	35,329	35,721

NCPA has proposed to use the following set of ERC certificates to offset NOx emissions increase from this project. The District has verified the amount of reduction in each certificate. Please note that all these certificates are owned by NCPA on September 30, 2008. Excess amount of NOx ERCs was proposed to be utilized to offset VOC emissions increase from this project.

Originally, NCPA also proposed to use certificate S-2769-2 and S-2770-2, which are not owned by NCPA. ERC S-2769-2 is owned by Bullard Energy Center LLC. ERC S-2770-2 is transferred to Nations Petroleum Limited (S-2927-2 in the amount of 0/9294/4654/9859) and Gulf Capital Partners (S-2928-2 in the amount of 0/0/0/4754 in Q1/Q2/Q3/Q4). **Both ERCs S-2769-2 and S-2770-2 are not included in the following table**, and are not reserved as part of the preliminary review process because sufficient amount of NOx reduction are available without these certificates to offset the NOx emissions increase.

ERC #	Original Reduction Site	Q1	Q2	Q3	Q4
S-2857-2	Bakersfield	0	0	0	1,031
S-2848-2	*HOW, Kern County	1,457	0	1,145	2,959
S-2849-2	HOW, Kern County	2,682	3,241	938	687
S-2850-2	HOW, Kern County	23,349	23,151	24,224	24,469
S-2851-2	HOW, Kern County	1,019	2,105	1,303	264
S-2852-2	HOW, Kern County	2,296	7,000	9,353	954
S-2854-2	HOW, Kern County	0	1,437	0	0
S-2855-2	HOW, Kern County	400	79	4,227	12,090
C-915-2	Hanford	129	137	122	117
C-916-2	Hanford	8,966	1,122	303	0
C-914-2	Fresno	4,702	6,728	3,983	1,831
N-755-2	4000 Yosemite Blvd, Modesto (>15 miles)	0	0	27,616	0
N-754-2	202 N Filbert, Stockton (<15 miles)	321	274	790	147
S-2894-2	Tupman	9,367	22,816	6,006	26,405
S-2895-2	HOW, Kern County	0	0	0	3,406
Total ERCs Available:		54,688	68,090	80,010	74,360

*Heavy Oil Western (HOW)

Using the maximum offset ratio of 1.5, this facility may have to offset the amount listed in following table for each quarter.

Category	Q1	Q2	Q3	Q4
Offset (EOQ x 1.5) (lb)	53,649	54,140	52,994	53,582
ERCs Available (lb)	54,688	68,090	80,010	74,360
Excess ERCs Available:	1,039	13,950	27,016	20,778

For each quarter, the amount of offsets required is less than the total amount of credits available in the proposed ERCs. Therefore, it is concluded that the proposed certificates are sufficient to offset the NOx emissions increase from this project.

The following condition will be listed on permits N-2697-5-0 and '-7-0:

- Prior to operating under ATCs N-2697-5-0 and N-2697-7-0, the permittee shall mitigate the following quantities of NOx: 1st quarter: 35,766 lb, 2nd quarter: 36,093 lb, 3rd quarter: 35,329 lb, and 4th quarter: 35,721 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 9/21/06). [District Rule 2201]

- NOx ERCs S-2857-2, S-2848-2, S-2849-2, S-2850-2, S-2851-2, S-2852-2, S-2854-2, S-2855-2, C-915-2, C-916-2, C-914-2, N-755-2, N-754-2, S-2894-2 and S-2895-2 (or a certificate split from any of these certificates) shall be used to supply the required NOx offsets, unless a revised offsetting proposal is received and approved by the District. Following the revisions, this Authority to Construct permit shall be re-issued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to re-issuance of this Authority to Construct permit. [District Rule 2201]

CO

Section 4.6.1 of Rule 2201 states that emission offsets shall not be required for increases in carbon monoxide in attainment areas if the applicant demonstrates to the satisfaction of the APCO, that the Ambient Air Quality Standards are not violated in the areas to be affected, and such emissions will be consistent with Reasonable Further Progress, and will not cause or contribute to a violation of Ambient Air Quality Standards.

San Joaquin Valley is in attainment for CO emissions. Based on the results of Ambient Air Quality Analysis (AAQA), Ambient Air Quality Standard (AAQS) for CO is not violated in the affected area. Therefore, offsets are not required for CO emissions increase. Please refer to Attachment F of this document for AAQA.

VOC

SSPE1 for VOC is greater than its respective Offset Threshold level. There is no increase in Cargo Carrier emissions from this project. BE is equal to zero for each emission unit. Thus,

EOQ = ΣPE2

Category	Q1	Q2	Q3	Q4
N-2697-5-0	8,077	8,157	9,732	8,915
N-2697-6-0	0	0	0	0
N-2697-7-0	39	39	21	30
EOQ (lb)	8,116	8,196	9,753	8,945

NCPA has proposed to use ERC certificate S-2748-1 to offset VOC emissions increase from this project. This certificate is divided among certificates S-2860-1 and S-2861-1. NCPA owns S-2860-1 that has 12,600 lb in each quarter. Since NCPA secured certificate S-2860-1 with 12,600 lb in each quarter, only this certificate is listed in the following table.

ERC #	Original Reduction Site	Q1	Q2	Q3	Q4
S-2860-1	Bakersfield	12,600	12,600	12,600	12,600
ERCs Available:		12,600	12,600	12,600	12,600

Using offset ratio of 1.5, this facility must offset the amount listed in following table for each quarter.

Category	Q1	Q2	Q3	Q4
Offset (EOQ x 1.5) (lb)	12,174	12,294	14,630	13,418
ERCs Available (lb)	12,600	12,600	12,600	12,600
Shortfall (lb)	0	0	2,030	818

To overcome the shortfall amount in 3rd and 4th quarter, NCPA has proposed to use NOx ERCs to offset VOC emissions increase.

Recently processed projects in Fresno and Modesto area (C1073739 and N1074322) set precedent to use NOx reductions for VOC increases at an inter-pollutant offset ratio of 1.0 for projects. District's latest 8-hour 'Ozone Plan 2007' was used as a rationale to use this inter-pollutant offset ratio. This plan indicate that more than one ton of VOC reductions are expected for every ton of NOx reduced provided that the emission activities and emission patterns, VOC reactivity and other parameters resulted in prediction of NOx and VOC over the coming year hold constant over time.

Category	Q1	Q2	Q3	Q4
Offset (Shortfall x 1.0) (lb)	0	0	2,030	818
NOx ERCs Available (lb)	1,039	13,950	27,016	20,778

From the above table, it is concluded that the proposed use of VOC and NOx ERCs would be sufficient to offset the VOC emissions increase from this project.

The following condition will be listed on permits N-2697-5-0 and '-7-0:

- Prior to operating under ATCs N-2697-5-0 and N-2697-7-0, the permittee shall mitigate the following quantities of VOC: 1st quarter: 8,116 lb, 2nd quarter: 8,196 lb, 3rd quarter: 9,753 lb, and 4th quarter: 8,945 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 9/21/06). [District Rule 2201]

- VOC ERC S-2860-1, and NOx ERCs S-2857-2, S-2848-2, S-2849-2, S-2850-2, S-2851-2, S-2852-2, S-2854-2, S-2855-2, C-915-2, C-916-2, C-914-2, N-755-2, N-754-2, S-2894-2 and S-2895-2 (or a certificate split from any of these certificates) shall be used to supply the required VOC offsets, unless a revised offsetting proposal is received and approved by the District. Following the revisions, this Authority to

Construct permit shall be re-issued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to re-issuance of this Authority to Construct permit. [District Rule 2201]

- The District has authorized to use NOx reductions to overcome shortfall in the amount of VOC offsets at NOx/VOC interpollutant offset ratio of 1.00. [District Rule 2201]

SOx

SSPE1 for SOx emissions is less than its respective Offset Threshold level. There is no increase in Cargo Carrier emissions from this project. Thus,

EOQ_{SOx} = SSPE2 lb/yr – 54,750 lb/yr = 60,274 lb/yr – 54,750 lb/yr = 5,524 lb/yr

EOQ on quarterly basis is determined by multiplying the emission percent contribution [i.e. Total (lb/quarter)/Total (lb/year)] with EOQ_{SOx} of 5,524 lb/yr. For example,

EOQ_{Q1} = (0.24)(5,524 lb/yr) = 1,326 lb

Category	Q1	Q2	Q3	Q4
N-2697-5-0	11,820	11,949	12,550	12,298
N-2697-7-0	26	26	14	20
PE2 (Total):	11,846	11,975	12,564	12,318
%	24%	25%	26%	25%
EOQ (lb)	1,326	1,381	1,436	1,381

NCPA has proposed to use the following set of ERC certificates to offset SOx emissions increase from this project. The District staff has verified the amount of reduction in each certificate. Please note that all these certificates are owned by NCPA on September 30, 2008. Excess amount of SOx ERCs will be used to offset PM_{10} emissions increase from this project.

ERC #	Original Reduction Site	Q1	Q2	Q3	Q4
S-2843-5	Tulare	13,298	10,631	12,619	13,452
S-2845-5	Tulare	7,998	9,131	7,319	8,152
S-2858-5	Bakersfield	9,100	9,100	9,080	9,100
N-759-5	4000 Yosemite Blvd, Modesto (>15 miles)	0	0	12,651	0
N-758-5	Merced	0	0	11,045	0
S-2846-5	Bakersfield	931	931	931	931
N-757-5	Merced	0	0	3,600	0
Total ERCs Available:		31,327	29,793	57,245	31,635

Using the offset ratio of 1.5, this facility must offset the amount listed in following table for each quarter.

Category	Q1	Q2	Q3	Q4
Offset (EOQ x 1.5) (lb)	1,989	2,072	2,154	2,072
ERCs Available (lb)	31,327	29,793	57,245	31,635
Excess ERCs Available:	29,338	27,721	55,091	29,563

For each quarter, the amount of offsets required is less than the total amount of credits available in the proposed ERCs. Therefore, it is concluded that the proposed certificates are sufficient to offset the SOx emissions increase from this project.

The following condition will be listed on permits N-2697-5-0 and '-7-0:

- Prior to operating under ATCs N-2697-5-0 and N-2697-7-0, the permittee shall mitigate the following quantities of SOx: 1st quarter: 1,326 lb, 2nd quarter: 1,381 lb, 3rd quarter: 1,436 lb, and 4th quarter: 1,381 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 9/21/06). [District Rule 2201]

- SOx ERCs S-2843-5, S-2845-5, S-2858-5, N-759-5, N-758-5, S-2846-5 and N-757-5 (or a certificate split from any of these certificates) shall be used to supply the required SOx offsets, unless a revised offsetting proposal is received and approved by the District. Following the revisions, this Authority to Construct permit shall be re-issued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to re-issuance of this Authority to Construct permit. [District Rule 2201]

PM_{10}

SSPE1 for PM_{10} emissions is less than its respective Offset Threshold level. There is no increase in Cargo Carrier emissions from this project. Thus,

EOQ_{PM10} = SSPE2 lb/yr – 29,200 lb/yr = 105,537 lb/yr – 29,200 lb/yr = 76,337 lb/yr

EOQ on quarterly basis is determined by multiplying the emission percent contribution [i.e. Total (lb/quarter)/Total (lb/year)] with EOQ_{PM10} of 76,337 lb/yr. For example,

EOQ_{Q1} = (0.24)(76,337 lb/yr) = 18,321 lb

Category	Q1	Q2	Q3	Q4
N-2697-5-0	20,140	20,356	22,072	21,272
N-2697-6-0	985	985	986	986
N-2697-7-0	70	70	38	53
PE2 (Total):	21,195	21,411	23,096	22,311
%	24%	24%	27*%	25%
EOQ (lb)	18,321	18,321	20,611	19,084

*adjusted to get 100%

NCPA has proposed to use the following set of ERC certificates to offset PM_{10} emissions increase from this project. The District staff verified the amount of reduction in each certificate. Please note that all these certificates are owned by NCPA on September 30, 2008.

ERC #	Original Reduction Site	Q1	Q2	Q3	Q4
S-2844-4	Shutdown of feedmill, Tulare	5,830	5,830	4,500	9,830
C-911-4	Shutdown of Cotton Gin Raisin City	0	0	0	4,244
N-756-4	Shutdown of three boilers 3200 E Eight Mile Road, Stockton (<15 miles)	81	78	583	58
C-913-4	Shutdown of boilers, Auberry	10	45	0	28
C-912-4	Shutdown of oil fired boilers, North Fork	60	0	8	5
	ERCs Available:	5,981	5,953	5,091	14,165

Using the maximum offset ratio of 1.5, this facility may have to offset the amount listed in following table for each quarter.

Category	Q1	Q2	Q3	Q4
Offset (EOQ x 1.5) (lb)	27,482	27,482	30,917	28,626
ERCs Available (lb)	5,981	5,953	5,091	14,165
Shortfall amount (lb):	21,501	21,529	25,826	14,461

Based on the modeling performed by the District (Refer to Attachment G of this document), SOx/PM_{10} inter-pollutant offset ratio is 1.0. This number is used to determine if NCPA has sufficient amount of SOx credits.

Category	Q1	Q2	Q3	Q4
PM_{10} Offset (Shortfall x 1.0) (lb)	21,501	21,529	25,826	14,461
SOx ERCs Available (lb)	29,338	27,721	55,091	29,563

Based on the above table, NCPA has sufficient amount of SOx credits. The following conditions will be placed on permits N-2697-5-0, '-6-0 and '-7-0:

- Prior to operating under ATCs N-2697-5-0, N-2697-6-0 and N-2697-7-0, the permittee shall mitigate the following quantities of PM_{10}: 1st quarter: 18,321 lb, 2nd quarter: 18,321 lb, 3rd quarter: 20,611 lb, and 4th quarter: 19,084 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 9/21/06). [District Rule 2201]

- PM_{10} ERCs S-2844-4, C-911-4, N-756-4, C-913-4, C-912-4, and SOx ERCs S-2843-5, S-2845-5, S-2858-5, N-759-5, N-758-5, S-2846-5 and N-757-5 (or a certificate split from any of these certificates) shall be used to supply the required PM10 offsets, unless a revised offsetting proposal is received and approved by the District. Following the revisions, this Authority to Construct permit shall be re-issued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to re-issuance of this Authority to Construct permit. [District Rule 2201]

- The District has authorized to use SOx reductions to overcome shortfall in the amount of PM10 offsets at SOx/PM10 interpollutant offset ratio of 1.00. [District Rule 2201]

3. Public Notice

District Rule 2201, section 5.4, requires a public notification for the affected pollutants from the following types of projects:

- New Major Sources
- Major Modifications
- New emission units with a PE>100 lb/day of any one pollutant
- Modifications with SSPE1 below an Offset threshold and SSPE2 above an Offset threshold on a pollutant-by-pollutant basis
- New stationary sources with SSPE2 exceeding Offset thresholds
- Any permitting action with a SSIPE exceeding 20,000 lb/yr for any one pollutant

Public notification is required for this project, as this project exceeded thresholds of many items listed above.

4. Daily Emission Limits (DELs)

Daily Emissions Limitations (DELs) and other enforceable conditions are required by Section 3.17 to restrict a unit's maximum daily emissions. The following conditions will be placed on the draft permits:

<u>N-2697-5-0</u>

- Emission rates from the gas turbine system during the commissioning period shall not exceed any of the following limits: NOx (as NO2) – 400.00 lb/hr and 4,000 lb/day; VOC (as CH4) – 16.00 lb/hr and 160.0 lb/day; CO – 2,000 lb/hr and 20,000 lb/day; PM10 - 11.00 lb/hr and 108.0 lb/day; or SOx (as SO2) – 6.00 lb/hr and 70.1 lb/day. [District Rule 2201]

- Except during startup and shutdown periods, emissions from the gas turbine system with duct burner firing shall not exceed any of the following limits: NOx (as NO2) – 15.25 lb/hr and 2.0 ppmvd @ 15% O2; CO – 13.93 lb/hr and 3 ppmvd @ 15% O2; VOC (as methane) – 5.32 lb/hr and 2.0 ppmvd @ 15% O2; PM10 – 11.00 lb/hr; or SOx (as SO2) – 6.00 lb/hr. NOx (as NO2) emission limits are based on 1-hour rolling average period. All other emission limits are based on 3-hour rolling average period. [District Rules 2201, 4001 and 4703]

- Except during startup and shutdown periods, emissions from the gas turbine system with no duct burner firing shall not exceed any of the following limits: NOx (as NO2) – 13.64 lb/hr and 2.0 ppmvd @ 15% O2; CO – 12.46 lb/hr and 3 ppmvd @ 15% O2; VOC (as methane) – 3.33 lb/hr and 1.4 ppmvd @ 15% O2; PM10 – 9.00 lb/hr; or SOx (as SO2) – 5.37 lb/hr. NOx (as NO2) emission limits are based on 1-hour rolling average period. All other emission limits are based on 3-hour rolling average period. [District Rules 2201, 4001 and 4703]

- During start-up and shutdown periods, the emissions shall not exceed any of the following limits: NO_X (as NO_2) – 160.00 lb/hr; CO – 900.00 lb/hr; VOC (as methane) – 16.00 lb/hr; PM_{10} – 9.00 lb/hr; SO_X (as SO_2) – 5.37 lb/hr; or NH_3 – 25.25 lb/hr. [District Rules 2201 and 4703]

- Emissions from the gas turbine system, on days when a startup and/or shutdown occurs, shall not exceed the following limits: NOx (as NO2) – 864.8 lb/day; CO – 5,642.0 lb/day; VOC – 179.8 lb/day; PM10 – 240.0 lb/day; SOx (as SO2) – 136.4 lb/day, or NH_3 – 641.8 lb/day. [District Rule 2201]

- Emissions from the gas turbine system, on days when a startup and/or shutdown does not occur, shall not exceed the following: NO_X (as NO_2) – 346.6 lb/day; CO – 316.8 lb/day; VOC – 103.8 lb/day; PM_{10} – 240.0 lb/day; SO_X (as SO_2) – 136.4 lb/day, or NH_3 – 641.8 lb/day. [District Rule 2201]

- NH3 emissions shall not exceed any of the following limits: 10.0 ppmvd @ 15% O2 over a 24-hour rolling average period, 25.25 lb/hr while gas turbine system operates with no duct burner firing and 28.23 lb/hr while gas turbine system operates with duct burner firing. [District Rule 2201]

The following emissions limits are placed to ensure compliance with quarterly emissions and or emission offsets.

- NOx (as NO_2) emissions from the gas turbine system shall not exceed any of the following: 1st quarter: 35,688 lb; 2nd quarter: 36,015 lb; 3rd quarter: 35,287 lb; 4th quarter: 35,661 lb. [District Rule 2201]

- CO emissions from the gas turbine system shall not exceed any of the following: 1st quarter: 147,429 lb; 2nd quarter: 147,728 lb; 3rd quarter: 93,691 lb; 4th quarter: 119,909 lb. [District Rule 2201]

- VOC emissions from the gas turbine system shall not exceed any of the following: 1st quarter: 8,077 lb; 2nd quarter: 8,157 lb; 3rd quarter: 9,732 lb; 4th quarter: 8,915 lb. [District Rule 2201]

- NH_3 emissions from the SCR system shall not exceed any of the following: 1st quarter: 55,584 lb; 2nd quarter: 56,190 lb; 3rd quarter: 59,030 lb; 4th quarter: 57,838 lb. [District Rule 2201]

- PM_{10} emissions from the gas turbine system shall not exceed any of the following: 1st quarter: 20,140 lb; 2nd quarter: 20,356 lb; 3rd quarter: 22,072 lb; 4th quarter: 21,272 lb. [District Rule 2201]

- SOx (as SO2) emissions from the gas turbine system shall not exceed any of the following: 1st quarter: 11,820 lb; 2nd quarter: 11,949 lb; 3rd quarter: 12,550 lb; 4th quarter: 12,298 lb. [District Rule 2201]

- Gas turbine system shall be fired on PUC-regulated natural gas with a sulfur content of no greater than 1.0 grain of sulfur compounds (as S) per 100 dscf of natural gas. [District Rule 2201 and 40 CFR 60.4330(a)(2)]

<u>N-2697-6-0</u>

- The drift rate shall not exceed 0.0005%. [District Rule 2201]

- PM10 emissions shall not exceed 10.8 pounds per day. [District Rule 2201]

<u>N-2697-7-0</u>

- NO_x (as NO_2) emissions shall not exceed 7.0 ppmvd @ 3% O_2 referenced as NO_2. [District Rules 2201, 4305, 4306 and 4320]

- CO emissions shall not exceed 50 ppmvd @ 3% O2. [District Rules 2201, 4305, 4306 and 4320]

- VOC (as CH_4) emissions shall not exceed 10.0 ppmvd @ 3% O2. [District Rule 2201]

- PM_{10} emissions shall not exceed 0.0076 lb/MMBtu. [District Rule 2201]

- SO_x emissions shall not exceed 0.00285 lb/MMBtu. [District Rule 2201]

- Heat input rate to this unit shall not exceed 780 MMBtu/day. [District Rule 2201]

The following emissions limits are placed to ensure compliance with quarterly emissions and emission offsets.

- NOx (as NO_2) emissions from this unit shall not exceed any of the following: 1st quarter: 78 lb; 2nd quarter: 78 lb; 3rd quarter: 42 lb; 4th quarter: 60 lb. [District Rule 2201]

- CO emissions from this unit shall not exceed any of the following: 1st quarter: 341 lb; 2nd quarter: 341 lb; 3rd quarter: 182 lb; 4th quarter: 259 lb. [District Rule 2201]

- VOC emissions from this unit shall not exceed any of the following: 1st quarter: 39 lb; 2nd quarter: 39 lb; 3rd quarter: 21 lb; 4th quarter: 30 lb. [District Rule 2201]

- PM_{10} emissions from this unit shall not exceed any of the following: 1st quarter: 70 lb; 2nd quarter: 70 lb; 3rd quarter: 38 lb; 4th quarter: 53 lb. [District Rule 2201]

- SOx (as SO2) emissions from this unit shall not exceed any of the following: 1st quarter: 26 lb; 2nd quarter: 26 lb; 3rd quarter: 14 lb; 4th quarter: 20 lb. [District Rule 2201]

5. Compliance Assurance

<u>Source Testing</u>

Source testing requirements are briefly explained in the following section for each permit unit.

N-2697-5-0

NCPA is required to perform a source test to measure hourly NOx, CO and VOC mass emission rates during the startup period. This test is required to be completed before the end of the commissioning period, and must be repeated at least once every seven years thereafter. PM_{10} emissions rate during the startup is expected to be same when gas turbine system operates in a steady-state mode, and therefore, it is not necessary to measure hourly PM_{10} mass emission rate during the startup period. SOx emissions during the startup period can be determined using sulfur content in the natural gas.

In addition, the NCPA is required to measure NO_x, CO, VOC, NH_3 and PM_{10} emissions during the steady state period. This test is required to be performed within 60 days after the end of commissioning period (approximately 90 days from the initial start-up) and must be repeated at least once every twelve months. NOx and CO tests are required to be performed with duct burner both in on and off configurations. This source test methodology is consistent with District Rule 4703, District Policy APR-1705 (10/9/97) and recently permitted similar facilities.

NCPA has proposed to use PUC regulated natural gas, and they are required to keep records of gas purchase receipts and or tariff and the amount of sulfur content in gas to demonstrate compliance with 1.0 grain-S/100 dscf of natural gas. If the sulfur content information is not available from the gas supplier, then the permittee is required to test fuel sulfur content on weekly basis. Upon successful compliance demonstration on 8 week consecutive tests, the test frequency shall be reduced to every six months. If any six-month test shows non-compliance with the sulfur content requirement, weekly testing will resume until eight consecutive weeks show compliance. This source test methodology is consistent with recently permitted similar facilities.

N-2697-6-0

The permittee is required to perform a blowdown water sample analysis by independent laboratory within 60 days after end of the commissioning period of the turbine system and quarterly thereafter. This sample analysis along with flow rate, drift and operating time is required to be used to demonstrate compliance with the permitted emission limits.

N-2697-7-0

Source test to measure NO_x and CO emissions is required to be conducted within 60 days after the end of commissioning period of the turbine system and annually thereafter. Successful compliance demonstration on two consecutive twelve-month tests may defer the following source test up to thirty-six months. The source test methodology is consistent with the source testing requirements of Rule 4306.

Monitoring

N-2697-5-0

The permittee has proposed to use a continuous emissions monitoring system (CEMS) to monitor NOx, CO and O_2 concentrations from the gas turbine system. CEMS is required to be installed, certified and operated in a manner required under 40 CFR Part 60 Subpart KKKK and Rule 4703.

Sulfur content in PUC regulated natural gas is expected to stay at or below 1.0 grain/100 scf. For this reason, it is expected that the gas turbine system will always be in compliance with SOx emissions limit. No separate SO_2 monitor is proposed by the NCPA or is required by the applicable District Rules or Federal regulations.

VOC and PM_{10} emissions will be monitored during each source test. Test results along with the heat input rate on hourly basis will assure on-going compliance with hourly, daily and quarterly emissions limits.

N-2697-6-0

The permittee is required to monitor water re-circulation rate (gal/day) and total dissolved solids (ppm) to demonstrate compliance with the daily emission limit.

N-2697-7-0

The permittee has proposed to use a portable analyzer that meet District specifications listed in District Policy SSP-1105, 4/28/08 to monitor NOx, CO and O_2 concentrations on monthly basis. The proposed monitoring scheme is typical for the boilers.

Recordkeeping

N-2697-5-0, '-6-0, '-7-0

The permittee is required to keep records of hourly emissions, daily emissions, quarterly emissions, source tests and monitoring parameters. These records are required to be kept for at least five years.

Reporting

N-2697-5-0, '-6-0, '-7-0

The applicant is required to submit source test results within 60 after each source test.

6. Ambient Air Quality Analysis (AAQA)

Section 4.14.1 requires an AAQA to be performed for projects that trigger public notice. The following table shows the summary of AAQA:

Criteria Pollutant Modeling Results*

Units N-2697-5-0, '-6-0 and '-7-0	1 Hour	3 Hours	8 Hours	24 Hours	Annual
CO	Pass	X	Pass	X	X
NO_x	Pass	X	X	X	Pass
SO_x	Pass	Pass	X	Pass	Pass
PM_{10}	X	X	X	Pass**	Pass**

*Results were taken from the PSD spreadsheets.
**The criteria pollutants are below EPA's level of significance as found in 40 CFR Part 51.165 (b)(2).

The criteria modeling runs for each unit indicate that the emissions will not cause or significantly contribute to a violation of the State or National Ambient Air Quality Standards. Please refer to Attachment F of this document for AAQA.

7. Alternative Siting and Compliance Certification

Section 4.15.1 states that sources for which an analysis of alternative sites, sizes, and production processes is required under Section 173 of the Federal Clean Air Act, the applicant shall prepare an analysis functionally equivalent to the requirements of Division 13, Section 21000 et. Seq. of the Public Resource Code.

NCPA has prepared and included an Alternative Siting analysis in the Application for Certification (AFC) to the CEC. CEC is the lead agency on CEQA, and their approval of the proposed Alternative Siting analysis will ensure compliance with this section. A copy of the proposed analysis is included in Attachment I of this document.

Section 4.15.2 requires the owner of a new Major Source or a Federal Major Modification to demonstrate to the satisfaction of the District that all other major Stationary Sources owned by such person in California are in compliance with all applicable emission limitations and standards.

NCPA has supplied a compliance certification that all major Stationary Sources owned or operated (or by any entity controlling, controlled by, or under common control) in California are in compliance with all applicable emission limitations and standards. In other words, none of their facility is under "Variance" from the applicable emission standards. This certification is included in Attachment I of this document.

Compliance is expected with this Rule.

Rule 2520 Federally Mandated Operating Permits

NCPA currently possesses a Title V permit. The proposed project is classified as "Significant Modification", as the project results in a Federal major modification, and is subject to NSPS standards listed in 40 CFR Part 60 subpart KKKK. The applicant has proposed to receive the ATCs with Certificates of Conformity in accordance with the requirements of 40 CFR 70.6(c), 70.7 and 70.8. Therefore, 45-day EPA notice will be conducted prior to the issuance of the ATCs. The following federally enforceable conditions will be placed on the ATCs:

- This Authority to Construct serves as a written Certificate of Conformity with the procedural requirements of 40 CFR 70.7 and 70.8 and with the compliance requirements of 40 CFR 70.6(c). [District Rule 2520]
- Prior to operating with the modifications authorized by this Authority to Construct, the facility shall submit an application for an administrative amendment to its Title V permit, in accordance with District Rule 2520, Section 11.4.2. [District Rule 2520]

In accordance with Rule 2520, the application meets the procedural requirements of section 11.4 by including:

- A description of the change, the emissions resulting from the change, and any new applicable requirements that will apply if the change occurs and

- The source's suggested draft permit (Attachment A of this document) and
- Certification by a responsible official that the proposed modification meets the criteria for use of major permit modification procedures and a request that such procedures be used (Attachment I of this document).

Section 5.3.4 of this rule requires the permittee shall file an application for administrative permit amendments prior to implementing the requested change except when allowed by the operational flexibility provisions of section 6.4 of this rule. NCPA is expected to notify the District by filing TV Form -008 upon implementing the ATCs. After successful compliance demonstration, the District Compliance Division is expected to submit a change order to implement these ATCs into Permits to Operate.

Compliance is expected with this Rule.

Rule 2540 Acid Rain Program

This rule is applicable to all stationary sources that are subject to Part 72, Title 40, Code of Federal Regulations (CFR). 40 CFR 72.30(b)(2)(iii) require submission of an acid rain permit application at least 24 months before the date the unit expects to generate electricity. This facility is anticipated to begin full-scale commercial operation by first quarter of 2012. The following condition will be placed on the permit:

- The permittee shall submit an application to comply with SJVUAPCD District Rule 2540 - Acid Rain Program. [District Rule 2540]

Compliance is expected with this Rule.

Rule 2550 Federally Mandated Preconstruction Review for Major Sources of Air Toxics

Section 2.0 states, "The provisions of this rule shall only apply to applications to construct or reconstruct a major air toxics source with Authority to Construct issued on or after June 28, 1998."

NCPA stated that this site is not a Major Source (i.e. PE >10 tons/yr for single HAP, PE > 25 tons/yr for combined HAPs). Therefore, this facility is not subject to the requirements of this Rule. Discussion and calculations related to this determination are given in the following section.

Non-criteria pollutants are compounds that have been identified as pollutants that pose a significant health hazard. Nine of these pollutants are regulated under the Federal New Source Review program: lead, asbestos, beryllium, mercury, fluorides, sulfuric acid mist, hydrogen sulfide, total reduced sulfur, and reduced sulfur compounds.[4]

[4] These pollutants are regulated under federal and state air quality programs; however, they are evaluated as noncriteria pollutants by the California Energy Commission (CEC).

In addition to these nine compounds, the federal Clean Air Act lists 189 substances as potential hazardous air pollutants (Clean Air Act Sec. 112(b)(1)). The SJVAPCD has also published a list of compounds it defines as potential toxic air contaminants (Toxics Policy, May 1991; Rule 2-1-316). Any pollutant that may be emitted from the project and is on the federal New Source Review List, the federal Clean Air Act list, and/or the SJVAPCD toxic air contaminant list has been evaluated.

N-2697-5-0

NCPA has identified non-criteria pollutant emission factors for the analysis of hazardous air emissions from the gas turbine. Except for hexane, polycyclic aromatic hydrocarbons (PAHs), and propylene oxide, the emission factors are obtained from AP-42 Table 3.1-3 (4/00). California Air Resources Board's California Air Toxics Emission Factors (CATEF) database for gas turbines (http://www.arb.ca.gov/app/emsinv/catef_form.html) was used to determine emissions for hexane, PAHs and propylene oxide. Mean values listed in the CATEF database was used in the analysis.

GE Frame 7 (with Duct Burners)

Hazardous Air Pollutant	Emission Factor (lb/MMBtu)(1)	Maximum Hourly Emissions (lb/hr) (2)	Maximum Annual Emissions (lb/yr) (3)	Maximum Annual Emissions (tpy)
Acetaldehyde	4.00E-05	8.43E-02	683	0.3
Acrolein	6.40E-06	1.35E-02	109	0.1
Benzene	1.20E-05	2.53E-02	205	0.1
1,3-Butadiene	4.30E-07	9.06E-04	7	0.0
Ethyl benzene	3.20E-05	6.74E-02	546	0.3
Formaldehyde	7.10E-04	1.50E+00	12,120	6.1
Hexane	2.58E-04	5.44E-01	4,404	2.2
Naphthalene	1.30E-06	2.74E-03	22	0.0
PAHs(4) (excluding Naphthalene)	3.14E-07	6.62E-04	5	0.0
Propylene Oxide	4.76E-05	1.00E-01	813	0.4
Toluene	1.30E-04	2.74E-01	2,219	1.1
Xylene	6.40E-05	1.35E-01	1,092	0.5
Total				**11.1**

(1) From AP-42 and CATEF databases.
(2) Based on an hourly heat input rate of 2,107.3 MMBtu/hr with duct burners.
(3) Based on total annual fuel use of 17,069,930 MMBtu/year (predicted by the applicant) and appears to be conservative number for the purposes of this calculation.
(4) Mean values of emission factors for Benzo(a)anthracene, Benzo(a)pyrene, Benzo(a)pyrene, Benzo(b)fluoranthrene, Benzo(k)fluoranthrene, Chrysene, Dibenz(a,h)anthracene, and ineno(1,2,3-cd)pyrene are obtained from CATEF database. These values are then adjusted by calculating the percentage of individual components in a combined total emission factor. This percentage is then multiplied with the difference of PAH and napthalene emission factor (9E-07 lb/MMBtu) and the individual weighted cancer risk relative to B(a)P. The obtained values are summed, which equates to 3.14E-07 lb/MMBtu.

N-2697-6-0

NCPA has identified noncriteria pollutant emission factors for the analysis of hazardous air emissions from the cooling tower.

Cooling Tower

Hazardous Air Pollutant	Concentration in cooling tower return water	Maximum Hourly Emissions (lb/hr) (1)	Maximum Annual Emissions (lb/yr) (2)	Maximum Annual Emissions (tpy)
Arsenic	0 ppm	0.00E+00	0.0	0.0
Cadmium	0.025 ppm	3.75E-06	0.0	0.0
Chromium III	0.025 ppm	3.75E-06	0.0	0.0
Lead	0.05 ppm	7.50E-06	0.1	0.0
Mercury	0 ppm	0.00E+00	0.0	0.0
Nickel	0.025 ppm	3.75E-06	0.0	0.0
Dioxins/furans	--	--	--	--
PAHs	--	--	--	--
Total				**0.0**

(1) Concentration (ppm) x Drift Rate (lb/hr). Drift Rate = 60,000 gpm x 60 min/hr x 5.00E-06 lb/lb-coolant x 8.34 lb-coolant/gal = 150.12 lb/hr
(2) Based on 8,760 hr/yr.

N-2697-7-0

The permittee has identified noncriteria pollutant emission factors for the analysis of hazardous air emissions from the auxiliary boiler. These emission factors are obtained from Ventura County APCD, "AB2588 Combustion Emission Factors" natural gas fired external combustion equipment 10-100 MMBtu/hr, available at http://www.vcapcd.org/pubs/Engineering/AirToxics/combem.pdf.

Auxiliary Boiler

Hazardous Air Pollutant	Emission Factor (lb/MMBtu)	Maximum Hourly Emissions (lb/hr) (1)	Maximum Annual Emissions (lb/yr) (2)	Maximum Annual Emissions (tpy)
Acetaldehyde	3.10E-06	2.02E-04	0.1	0.0
Acrolein	2.70E-06	1.76E-04	0.1	0.0
Benzene	5.800E-06	3.77E-04	0.2	0.0
1,3-Butadiene	n/a	--	--	--
Ethyl benzene	6.90E-06	4.49E-04	0.2	0.0
Formaldehyde	1.23E-05	8.00E-04	0.4	0.0
Hexane	4.60E-06	2.99E-04	0.1	0.0

Auxiliary Boiler (Continue...)

Hazardous Air Pollutant	Emission Factor (lb/MMBtu)	Maximum Hourly Emissions (lb/hr) (1)	Maximum Annual Emissions (lb/yr) (2)	Maximum Annual Emissions (tpy)
Naphthalene	3.00E-07	1.95E-05	0.0	0.0
PAHs(4) (excluding Naphthalene	1.00E-07	6.50E-06	0.0	0.0
Propylene Oxide	n/a	--	--	--
Toluene	2.65E-05	1.72E-03	0.8	0.0
Xylene	6.40E-08	4.16E-06	0.0	0.0
Total				**0.0**

(1) Based on a maximum hourly fuel use of 65 MMBtu/hr.
(2) Based on total annual fuel use of 30,420 MMBtu/year.

NCPA also operates a gas turbine system (N-2697-1-3) and a diesel-fueled emergency fire pump engine (N-2697-4-2). These units were issued permits before June 28, 1998. Therefore, units are not subject to the requirements of this Rule. However, HAPs are calculated to determine the total HAPs from this facility. This information will also be used to determine the applicability of NESHAP standards of 40 CFR 63 Subpart YYYY.

N-2697-1-3

GE LM 5000 with Steam Injection

Hazardous Air Pollutant	Emission Factor (lb/MMBtu)(1)	Maximum Hourly Emissions (lb/hr) (2)	Maximum Annual Emissions (lb/yr) (3)	Maximum Annual Emissions (tpy)
Acetaldehyde	4.00E-05	1.85E-02	162	0.1
Acrolein	6.40E-06	2.96E-03	26	0.0
Benzene	1.20E-05	5.56E-03	49	0.0
1,3-Butadiene	4.30E-07	1.99E-04	2	0.0
Ethyl benzene	3.20E-05	1.48E-02	130	0.1
Formaldehyde	7.10E-04	3.29E-01	2,880	1.4
Hexane	2.58E-04	1.19E-01	1,046	0.5
Naphthalene	1.30E-06	6.02E-04	5	0.0
PAHs	1.30E-07	6.62E-05	1	0.0
Propylene Oxide	4.76E-05	2.20E-02	193	0.1
Toluene	1.30E-04	6.02E-02	527	0.3
Xylene	6.40E-05	2.96E-02	260	0.1
Total				**2.6**

(1) Except PAH, emission factor are same as identified under N-2697-5-0. For PAH, NCPA identified an emission factor of 1.30E-06
(2) Based on an hourly heat input rate of 463 MMBtu/hr.
(3) Based on total annual fuel use of 4,055,880 MMBtu/year based on 8,760 hr/yr operation

N-2947-4-2

240 bhp Diesel-Fueled Emergency Engine

Hazardous Air Pollutant	Emission Factor (lb/MMBtu)(1)	Maximum Hourly Emissions (lb/hr) (2)	Maximum Annual Emissions (lb/yr) (3)	Maximum Annual Emissions (tpy)
Acetaldehyde	7.67E-04	1.23E-03	0	0.0
Acrolein	9.25E-05	1.48E-04	0	0.0
Benzene	9.33E-04	1.49E-03	0	0.0
1,3-Butadiene	3.91E-05	6.26E-05	0	0.0
Ethyl benzene	--	--	--	--
Formaldehyde	1.18E-03	1.89E-03	0	0.0
Hexane	n/a	--	--	--
Naphthalene	8.48E-05	1.36E-04	0	0.0
PAHs	8.32E-05	1.33E-04	0	0.0
Propylene Oxide	n/a	--	--	0.0
Toluene	4.09E-04	6.54E-04	0	0.0
Xylene	2.85E-04	4.56E-04	0	0.0
Total				**0.0**

(1) AP-42 Table 3.3.-2 (10/96)
(2) Based on an hourly heat input rate of 1.6 MMBtu/hr (11.9 gal/hr x 0.137 MMBtu/gal).
(3) Per ATCM, this engine is allowed to be operated for 30 hr/yr for non-emergency purposes. Therefore, annual heat input rate would be 48 MMBtu/yr.

Summary:

The combined total single HAP emissions from the units proposed under this project and the existing units are less than 10 tons/yr. Furthermore, the combined total of multiple HAP emissions from the units proposed under this project and the existing emission units are less than 25 tons/yr. Therefore, it is concluded this facility is not a Major Source for air toxics.

Rule 4001 New Source Performance Standards (NSPS)

The proposed CTG and the auxiliary boiler are subject to the requirements of this Rule. The applicable subparts are given below:

N-2657-5-0: 40 CFR Part 60 Subpart GG - Standards of Performance for Stationary Gas Turbines

40 CFR Part 60 Subpart KKKK – Standards of Performance for Stationary Combustion Turbines

N-2657-6-0: 40 CFR Part 60 Subpart Dc – Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units

Detailed discussion on the requirements of each subpart is given below for each permit unit. NCPA's proposal meets all the requirements of the applicable subparts. Therefore, compliance is expected with the NSPS.

N-2697-5-0

40 CFR Part 60 Subpart GG - Standards of Performance for Stationary Gas Turbines

40 CFR Part 60 Subpart KKKK, Section 60.4305(b), states that stationary combustion turbines regulated under this subpart are exempt from the requirements of 40 CFR 60 Subpart GG.

The proposed turbine is regulated under 40 CFR Part 60 Subpart KKKK. Therefore, it is exempt from the requirements of 40 CFR Part 60 Subpart GG and no further discussion is required.

40 CFR Part 60 Subpart KKKK – Standards of Performance for Stationary Combustion Turbines

The requirements of the 40 CFR Part 60, Subpart KKKK apply to a stationary combustion turbine with heat input (at peak load) equal to or greater than 10 MMBtu/hr, and that commenced construction, modification or reconstruction after February 18, 2005. This subpart regulates nitrogen oxide (NO_X) and sulfur dioxide (SO_X) emissions only.

The proposed gas turbine is rated at 1,885.3 MMBtu/hr and will be installed after 2/18/05. Therefore, this turbine is subject to the requirements of this subpart.

Section 60.4320 - Standards for Nitrogen Oxides

Paragraph (a) states that NO_X emissions shall not exceed the emission limits specified in Table 1 of this subpart. Paragraph (b) states that if you have two or more turbines that are connected to a single generator, each turbine must meet the emission limits for NO_X. Table 1 states that new, modified, or reconstructed turbines firing natural gas with a heat input at peak load of greater than 850 MMBtu/hr shall meet a NO_X emissions limit of 15 ppmvd @ 15% O_2 or 54 ng/J of useful output (0.43 lb/MWh). This limit is based on 4-hour rolling average or 30-day rolling average as defined in §60.4380(b)(1).

NCPA has proposed to meet 2.0 ppmvd NOx @ 15% O_2 on one-hour rolling average period. NCPA is expected to meet this limit. Permit condition enforcing this requirement is provided under Rule 2201 (DELs).

Section 60.4330 - Standards for Sulfur Dioxide

Paragraph (a) states that if your turbine is located in a continental area, you must comply with one of the following:

(1) Operator must not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO_2 in excess of 110 nanograms per Joule (ng/J) (0.90) pounds per megawatt-hour (lb/MWh)) gross output; or

(2) Operator must not burn in the subject stationary combustion turbine any fuel which contains total potential sulfur emissions in excess of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input.

NCPA has proposed to use PUC-regulated natural gas in the gas turbine and duct burners with a sulfur content of 1.0 grain/ 100 scf or less. The following condition will ensure compliance with the requirements of this section:

- Gas turbine system shall be fired on PUC-regulated natural gas with a sulfur content of no greater than 1.0 grain of sulfur compounds (as S) per 100 dscf of natural gas. [District Rule 2201 and 40 CFR 60.4330(a)(2)]

Section 60.4335 – NO_X Compliance Demonstration, with Water or Steam Injection

Paragraph (a) states that when a turbine is using water or steam injection to reduce NO_X emissions, you must install, calibrate, maintain and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel being fired in the turbine when burning a fuel that requires water or steam injection for compliance.

NCPA is not proposing to inject water or steam in the CTG. Therefore, the requirements of this section are not applicable.

Section 60.4340 – NO_X Compliance Demonstration, without Water or Steam Injection

Paragraph (b) states that as an alternative to annual source testing, the facility may install, calibrate, maintain and operate one of the following continuous monitoring systems:

(1) Continuous emission monitoring as described in §60.4335(b) and 60.4345, or
(2) Continuous parameter monitoring

NCPA has proposed to install a CEMS system as described in §60.4335(b) and 60.4345. The following condition will ensure compliance with the requirements of this section:

- The owner or operator shall install, certify, maintain, operate, and quality-assure a continuous emission monitor system (CEMS) which continuously measures and records the exhaust gas NOx, CO, and O2 concentrations. Continuous emissions monitors shall be capable of monitoring emissions during normal operating conditions and during startups and shutdowns, provided that CEMS passes the relative accuracy requirement listed in 40 CFR Part 60, Appendix B, Performance Specification 2 (PS-2). If relative accuracy of CEMS cannot be demonstrated during the startup, CEMS results during startup and shutdown events shall be replaced with startup emission rates obtained from the source test to determine compliance with emission limits contained in this document. [District Rules 1080, 2201 and 4703, 40 CFR 60.4340(b)(1) and 40 CFR 60.4345(a)]

Section 60.4345 – CEMS Equipment Requirements

Paragraph (a) states that each NO_X diluent CEMS must be installed and certified according to Performance Specification 2 (PS 2) in Appendix B to this part, except the 7-day calibration drift is based on unit operating days, not calendar days. With state approval, Procedure 1 in Appendix F to this part is not required. Alternatively, a NO_X diluent CEMS that is installed and certified according to Appendix A of Part 75 of this chapter is acceptable for use under this subpart. The relative accuracy test audit (RATA) of the CEMS shall be performed on a lb/MMBtu basis.

Paragraph (b) states that as specified in §60.13(e)(2), during each full unit operating hour, both the NO_X monitor and the diluent monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour, to validate the hour. For partial unit operating hours, at least one valid data point must be obtained with each monitor for each quadrant of the hour in which the unit operates. For unit operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two valid data points (one in each of two quadrants) are required for each monitor to validate the NO_X emission rate for the hour.

Paragraph (c) states that each fuel flow meter shall be installed, calibrated, maintained, and operated according to the manufacturer's instructions. Alternatively, with state approval, fuel flow meters that meet the installation, certification, and quality assurance requirements of Appendix D to Part 75 of this chapter are acceptable for use under this subpart.

Paragraph (d) states that each watt meter, steam flow meter, and each pressure or temperature measurement device shall be installed, calibrated, maintained, and operated according to manufacturer's instructions.

Paragraph (e) states that the owner or operator shall develop and keep on-site a quality assurance (QA) plan for all of the continuous monitoring equipment described in paragraphs (a), (c), and (d) of this section. For the CEMS and fuel flow meters, the owner or operator may, with state approval, satisfy the requirements of this paragraph by implementing the QA program and plan described in section 1 of Appendix B to Part 75 of this chapter.

NCPA has proposed to install and operate a NO_X CEMS to meet the requirements of this section. NCPA is not required to install a fuel flow meter, watt meter, steam flow meter, or a pressure or temperature measurement device to comply with the requirements of this subpart. The following conditions will ensure compliance with the requirements of this section:

- NO_X, CO and O_2 CEMS shall meet the requirements in 40 CFR Part 60, Appendix F Procedure 1 and Part 60, Appendix B Performance Specification 2 (PS 2), or shall meet equivalent specifications established by mutual agreement of the District, the CARB, and the EPA. [District Rule 1080 and 40 CFR 60.4345(a)]

- The CEMS shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour or shall meet equivalent specifications established by mutual agreement of the District, the CARB and the EPA. [District Rule 1080 and 40 CFR 60.4345(b)]

Section 60.4350 – CEMS Data and Excess NO_X Emissions

Section 60.4350 states that for purposes of identifying excess emissions:

(a) All CEMS data must be reduced to hourly averages as specified in §60.13(h).

(b) For each unit operating hour in which a valid hourly average, as described in §60.4345(b), is obtained for both NO_X and diluent monitors, the data acquisition and handling system must calculate and record the hourly NO_X emission rate in units of ppm or lb/MMBtu, using the appropriate equation from Method 19 in Appendix A of this part. For any hour in which the hourly average O_2 concentration exceeds 19.0 percent O_2 (or the hourly average CO_2 concentration is less than 1.0 percent CO_2), a diluent cap value of 19.0 percent O_2 or 1.0 percent CO_2 (as applicable) may be used in the emission calculations.

(c) Correction of measured NO_X concentrations to 15 percent O_2 is not allowed.

(d) If you have installed and certified a NO_X diluent CEMS to meet the requirements of Part 75 of this chapter, states can approve that only quality assured data from the CEMS shall be used to identify excess emissions under this subpart. Periods where the missing data substitution procedures in Subpart D of Part 75 are applied are to be reported as monitor downtime in the excess emissions and monitoring performance report required under §60.7(c).

(e) All required fuel flow rate, steam flow rate, temperature, pressure, and megawatt data must be reduced to hourly averages.

(f) Calculate the hourly average NO_X emission rates, in units of the emission standards under §60.4320, using either ppm for units complying with the concentration limit or the equations 1 (simple cycle turbines) or 2 (combined cycle turbines) listed in §60.4350, paragraph (f).

NCPA has proposed to monitor the NO_X emissions rate from the turbine with a CEMS. The CEMS system will be used to determine if, and when, any excess NO_X emissions are released to the atmosphere. The CEMS is expected to be operated in accordance with the methods and procedures described above. The following condition will ensure compliance with the requirements of this section:

- The CEMS data shall be reduced to hourly averages as specified in §60.13(h) and in accordance with §60.4350, or by other methods deemed equivalent by mutual agreement with the District, the CARB, and the EPA. [District Rule 1080 and 40 CFR 60.4350]

Section 60.4355 – Parameter Monitoring Plan

This section set forth the requirements for operators that elect to continuously monitor parameters in lieu of installing a CEMS for NO_X emissions. As discussed above, NCPA is proposing to install CEMS that will directly measure NO_X emissions. Therefore, the requirements of this section are not applicable and no further discussion is required.

Sections 60.4360, 60.4365 and 60.4370 – Monitoring of Fuel Sulfur Content

Section 60.4360 states that an operator must monitor the total sulfur content of the fuel being fired in the turbine, except as provided in §60.4365. The sulfur content of the fuel must be determined using total sulfur methods described in §60.4415. Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than half the applicable limit, ASTM D4084, D4810, D5504, or D6228, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see §60.17), which measure the major sulfur compounds, may be used.

Section 60.4365 states that an operator may elect not to monitor the total sulfur content of the fuel combusted in the turbine, if the fuel is demonstrated not to exceed potential sulfur emissions of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for units located in continental areas and 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for units located in no continental areas or a continental area that the Administrator determines does not have access to natural gas and that the removal of sulfur compounds would cause more environmental harm than benefit. You must use one of the following sources of information to make the required demonstration:

(a) The fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel, specifying that the maximum total sulfur content for oil use in continental areas is 0.05 weight percent (500 ppmw) or less and 0.4 weight percent (4,000 ppmw) or less for no continental areas, the total sulfur content for natural gas use in continental areas is 20 grains of sulfur or less per 100 standard cubic feet and 140 grains of sulfur or less per 100 standard cubic feet for no continental areas, has potential sulfur emissions of less than less than 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for continental areas and has potential sulfur emissions of less than less than 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for no continental areas; or

(b) Representative fuel sampling data which show that the sulfur content of the fuel does not exceed 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for continental areas or 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for non-continental areas. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of Appendix D to Part 75 of this chapter is required.

NCPA has proposed to use PUC regulated natural gas that may contain up to 1.0 grain-S/100 scf. Primarily, the natural gas suppliers are able to provide a purchase contract, tariff sheet or transportation contract for the fuel that demonstrates compliance with this natural gas sulfur content limit. If the sulfur content information is not available from the gas supplier, then the permittee is required to test fuel sulfur content on weekly basis. Upon successful compliance demonstration on 8 week consecutive tests, the test frequency shall be reduced to every six months. If any six-month test shows non-compliance with the sulfur content requirement, weekly testing will resume until eight consecutive weeks show compliance.

Section 60.4370 states that the frequency of determining the sulfur content of the fuel must be as follows:

(a) *Fuel oil:* For fuel oil, use one of the total sulfur sampling options and the associated sampling frequency described in sections 2.2.3, 2.2.4.1, 2.2.4.2, and 2.2.4.3 of Appendix D to Part 75 of this chapter (*i.e.*, flow proportional sampling, daily sampling, sampling from the unit's storage tank after each addition of fuel to the tank, or sampling each delivery prior to combining it with fuel oil already in the intended storage tank).

(b) *Gaseous fuel:* If you elect not to demonstrate sulfur content using options in §60.4365, and the fuel is supplied without intermediate bulk storage, the sulfur content value of the gaseous fuel must be determined and recorded once per unit operating day.

(c) *Custom schedules:* Notwithstanding the requirements of paragraph (b) of this section, operators or fuel vendors may develop custom schedules for determination of the total sulfur content of gaseous fuels, based on the design and operation of the affected facility and the characteristics of the fuel supply. Except as provided in paragraphs (c)(1) and (c)(2) of this section, custom schedules shall be substantiated with data and shall be approved by the Administrator before they can be used to cornply with the standard in §60.4330.

The District and EPA have previously approved a custom monitoring schedule of at least one per week. Then, if compliance with the fuel sulfur content limit is demonstrated for eight consecutive weeks, the monitoring frequency shall be at least once every six months. If any six month monitoring period shows an exceedance, weekly monitoring shall resume. The following condition will ensure continued compliance with the requirements of this section:

- The sulfur content of each fuel source shall be: (i) documented in a valid purchase contract, a supplier certification, a tariff sheet or transportation contract, or (ii) monitored within 60 days after the end of commissioning period and weekly thereafter. If the sulfur content is less than or equal to 1.0 gr/100 dscf for eight consecutive weeks, then the monitoring frequency shall be every six months. If the result of any six month monitoring demonstrates that the fuel does not meet the fuel sulfur content limit, weekly monitoring shall resume until compliance is demonstrated for eight consecutive weeks. [District Rule 2201 and 40 CFR 60.4360, 60.4365(a) and 60.4370(c)]

Section 60.4380 – Excess NO_X Emissions and Monitor Downtime

Section 60.4380 establishes reporting requirements for periods of excess emissions and monitor downtime. Paragraph (a) lists requirements for operators choosing to monitor parameters associated with water or steam to fuel ratios. As discussed above, NCPA is not proposing to monitor parameters associated with water or steam to fuel ratios to predict NO_X emissions. Therefore, the requirements of this paragraph are not applicable and no further discussion is required.

Paragraph (b) states that for turbines using CEM's:

(1) An excess emissions is any unit operating period in which the 4-hour or 30-day rolling average NO_X emission rate exceeds the applicable emission limit in §60.4320. For the purposes of this subpart, a "4-hour rolling average NO_X emission rate" is the arithmetic average of the average NO_X emission rate in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given hour and the three unit operating hour average NO_X emission rates immediately preceding that unit operating hour. Calculate the rolling average if a valid NO_X emission rate is obtained for at least 3 of the 4 hours. For the purposes of this subpart, a "30-day rolling average NO_X emission rate" is the arithmetic average of all hourly NO_X emission data in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given day and the twenty-nine unit operating days immediately preceding that unit operating day. A new 30-day average is

calculated each unit operating day as the average of all hourly NO_X emissions rates for the preceding 30 unit operating days if a valid NO_X emission rate is obtained for at least 75 percent of all operating hours.

NCPA has proposed to emit less than or equal to 2.0 ppmvd NOx @ 15% O_2, 15.25 lb-NOx/hr (with duct burner firing) and 13.64 lb-NOx/hr (with no duct firing) on 1-hour rolling average period. Emissions excess of these standards will constitute a violation of the permitted limits. These emissions standards and the averaging period are more stringent that of the ones listed above in section 40 CFR 60.4380(b)(1). Therefore, compliance with this section will be assured by complying with the permitted limit.

(2) A period of monitor downtime is any unit operating hour in which the data for any of the following parameters are either missing or invalid: NO_X concentration, CO2 or O_2 concentration, fuel flow rate, steam flow rate, steam temperature, steam pressure, or megawatts. The steam flow rate, steam temperature, and steam pressure are only required if you will use this information for compliance purposes. The following permit condition is placed to assure compliance with this section.

- Monitor Downtime is defined as any unit operating hour in which the data for NOx, CO_2 or O_2 concentrations is either missing or invalid. [40 CFR 60.4380(b)(2)]

(3) For operating periods during which multiple emissions standards apply, the applicable standard is the average of the applicable standards during each hour. For hours with multiple emissions standards, the applicable limit for that hour is determined based on the condition that corresponded to the highest emissions standard.

Paragraph (c) lists requirements for operators who choose to monitor combustion parameters that document proper operation of the NO_X emission controls. NCPA is not proposing to monitor combustion parameters that document proper operation of the NO_X emission controls. Therefore, the requirements of this paragraph are not applicable and no further discussion is required.

Section 60.4385 – Excess SO_X Emissions and Monitoring Downtime

Section 60.4385 states that if an operator chooses the option to monitor the sulfur content of the fuel, excess emissions and monitoring downtime are defined as follows:

(a) For samples of gaseous fuel and for oil samples obtained using daily sampling, flow proportional sampling, or sampling from the unit's storage tank, an excess emission occurs each unit operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the combustion turbine exceeds the applicable limit and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit.

(b) If the option to sample each delivery of fuel oil has been selected, you must immediately switch to one of the other oil sampling options (i.e., daily sampling, flow proportional sampling, or sampling from the unit's storage tank) if the sulfur content of a delivery exceeds 0.05 weight percent. You must continue to use one of the other sampling options until all of the oil from the delivery has been combusted, and you must evaluate excess emissions according to paragraph (a) of this section. When all of the fuel from the delivery has been burned, you may resume using the as-delivered sampling option.

(c) A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour of a required sample, if invalid results are obtained. The period of monitor downtime ends on the date and hour of the next valid sample.

NCPA is expected to follow the definitions and procedures specified above for determining periods of excess SO_X emissions. Compliance is expected with this section.

Sections 60.4375 and 60.4395 – Reports Submittal

Section 60.4375(a) states that for each affected unit required to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content under this subpart, you must submit reports of excess emissions and monitor downtime, in accordance with §60.7(c). Excess emissions must be reported for all periods of unit operation, including start-up, shutdown, and malfunction.

Section 60.4375(b) states that for each affected unit that performs annual performance tests in accordance with §60.4340(a), you must submit a written report of the results of each performance test before the close of business on the 60th day following the completion of the performance test.

Section 60.4395 states All reports required under §60.7(c) must be postmarked by the 30th day following the end of each 6-month period.

NCPA is proposing to maintain records and submit reports in accordance with the requirements specified in these sections. The following condition will ensure compliance with the requirements of this section:

- The owner or operator shall submit a written report of CEM operations for each calendar quarter to the APCO. The report is due on the 30th day following the end of the calendar quarter and shall include the following: Time intervals, data and magnitude of excess NOx emissions, nature and the cause of excess (if known), corrective actions taken and preventive measures adopted; Averaging period used for data reporting corresponding to the averaging period specified in the emission test period used to determine compliance with an emission standard; Applicable time and date of each period during which the CEM was inoperative, except for zero and span checks, and the nature of system repairs and adjustments; A negative declaration when no excess emissions occurred. [District Rule 1080 and 40 CFR 60.4375(a) and 60.4395]

Section 60.4400 – NO_X Performance Testing

Section 60.4400, paragraph (a) states that an operator must conduct an initial performance test, as required in §60.8. Subsequent NO_X performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test).

Paragraphs (1), (2) and (3) set fourth the requirements for the methods that are to be used during source testing.

NCPA will be required to source test within 60 days after the end of the commissioning period (i.e. 90 days of initial startup) and at least once every 12 months thereafter. They will be required to source test in accordance with the methods and procedures specified in paragraphs (1), (2), and (3). The following conditions will ensure compliance with the requirements of this section:

- Source testing to determine compliance with the NOx, CO, VOC and NH3 emission rates (lb/hr and ppmvd @ 15% O_2) and PM_{10} emission rate (lb/hr) shall be conducted within 60 days after the end of commissioning period and at least once every 12 months thereafter. [District Rules 2201 and 4703, 40 CFR 60.4400(a)]

- The following test methods shall be used: NO_X - EPA Method 7E or 20 or CARB Method 100; CO - EPA Method 10 or 10B or CARB Method 100; VOC - EPA Method 18 or 25; PM10 - EPA Method 5 (front half and back half) or 201 and 202a; ammonia - BAAQMD ST-1B; and O_2 - EPA Method 3, 3A, or 20 or CARB Method 100. EPA approved alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4703 and 40 CFR 60.4400(1)(i)]

Section 60.4405 – Initial CEMS Relative Accuracy Testing

Section 60.4405 states that if you elect to install and certify a NO_X-diluent CEMS, then the initial performance test required under §60.8 may be performed in the alternative manner described in paragraphs (a), (b), (c) and (d). NCPA has not indicated that they would like to perform the initial performance test of the CEMS using the alternative methods described in this section.. Therefore, the requirements of this section are not applicable and no further discussion is required.

Section 60.4410 – Parameter Monitoring Ranges

Section 60.4410 sets fourth requirements for operators that elect to monitor combustion parameters or parameters indicative of proper operation of NO_X emission controls. As discussed above, NCPA is proposing to install a CEMS system to monitor the NO_X emissions for the turbine and is not proposing to monitor combustion parameters or parameters indicative of proper operation. Therefore, the requirements of this section are not applicable and no further discussion is required.

Section 60.4415– SO_X Performance Testing

Section 60.4415 states that an operator must conduct an initial performance test, as required in §60.8. Subsequent SO_2 performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test). There are three methodologies that you may use to conduct the performance tests.

(1) If you choose to periodically determine the sulfur content of the fuel combusted in the turbine, a representative fuel sample would be collected following ASTM D5287 (incorporated by reference, see §60.17) for natural gas or ASTM D4177 (incorporated by reference, see §60.17) for oil. Alternatively, for oil, you may follow the procedures for manual pipeline sampling in section 14 of ASTM D4057 (incorporated by reference, see §60.17). The fuel analyses of this section may be performed either by you, a service contractor retained by you, the fuel vendor, or any other qualified agency. Analyze the samples for the total sulfur content of the fuel using:

(i) For liquid fuels, ASTM D129, or alternatively D1266, D1552, D2622, D4294, or D5453 (all of which are incorporated by reference, see §60.17); or

(ii) For gaseous fuels, ASTM D1072, or alternatively D3246, D4084, D4468, D4810, D6228, D6667, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see §60.17).

NCPA is expected to periodically determine the sulfur content of the fuel combusted in the turbine when valid purchase contracts, tariff sheets or transportation contract are not available. The sulfur content will be determined using the methods specified above. The following condition will ensure compliance with the requirements of this section:

- Fuel sulfur content shall be monitored using one of the following methods: ASTM Methods D1072, D3246, D4084, D4468, D4810, D6228, D6667 or Gas Processors Association Standard 2377. [40 CFR 60.4415(a)(1)(i)]

Methodologies (2) and (3) are applicable to operators that elect to measure the SO_2 concentration in the exhaust stream. NCPA is not proposing to measure the SO_2 in the exhaust stream of the turbine. Therefore, the requirements of these methodologies are not applicable and no further discussion is required.

Compliance is expected with this Subpart.

N-2697-7-0

40 CFR Part 60 Subpart Dc – Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units

This subpart applies to steam generating units that are constructed, reconstructed, or modified after 6/9/89 and have a maximum design heat input capacity of 100 MMBtu/hr or less, but greater than or equal to 10 MMBtu/hr. Subpart Dc has standards for SO_X and PM_{10}.

60.42c – Standards for Sulfur Dioxide

Since coal is not combusted in the proposed boiler, the requirements of this section are not applicable.

60.43c – Standards for Particulate Matter

The boiler is not fired on coal, combusts mixtures of coal with other fuels, combusts wood, combusts mixtured of wood with other fuels, or oil; therefore it will not be subject to the requirements of this section.

60.44c – Compliance and Performance Tests Methods and Procedures for Sulfur Dioxide

The proposed boiler is not subject to the sulfur dioxide requirements of this subpart. Therefore, this section is not applicable to this unit.

60.45c – Compliance and Performance Test Methods and Procedures for Particulate Matter

The proposed boiler is not subject to the particulate matter requirements of this subpart. Therefore, this section is not applicable to this unit.

60.46c – Emission Monitoring for Sulfur Dioxide

The proposed boiler is not subject to the sulfur dioxide requirements of this subpart. Therefore, this section is not applicable to this unit.

60.47c – Emission Monitoring for Particulate Matter

The proposed boiler is not subject to the particulate matter requirements of this subpart. Therefore, this section is not applicable to this unit.

60.48c – Reporting and Recordingkeeping Requirements

Section 60.48c (a) states that the owner or operator of each affected facility shall submit notification of the date of construction or reconstruction, anticipated startup, and actual startup, as provided by §60.7 of this part. This notification shall include:

(1) The design heat input capacity of the affected facility and identification of fuels to be combusted in the affected facility.

The design heat input capacity and type of fuel combusted at the facility will be listed on the unit's equipment description. No conditions are required to show compliance with this requirement.

(2) If applicable, a copy of any Federally enforceable requirement that limits the annual capacity factor for any fuel mixture of fuels under §60.42c or §40.43c.

This requirement is not applicable since the units are not subject to §60.42c or §60.43c.

(3) The annual capacity factor at which the owner or operator anticipates operating the affected facility based on all fuels fired and based on each individual fuel fired.

The facility has not proposed an annual capacity factor; therefore one will not be required.

(4) Notification if an emerging technology will be used for controlling SO_2 emissions. The Administrator will examine the description of the control device and will determine whether the technology qualifies as an emerging technology. In making this determination, the Administrator may require the owner or operator of the affected facility to submit additional information concerning the control device. The affected facility is subject to the provisions of §60.42c(a) or (b)(1), unless and until this determination is made by the Administrator

This requirement is not applicable since the units will not be equipped with an emerging technology used to control SO_2 emissions.

Section 60.48c(g) states that the owner or operator of each affected facility shall record and maintain records of the amounts of each fuel combusted during each day. The following conditions will be listed in the permit to assure compliance with this section.

- A non-resettable, totalizing mass or volumetric fuel flow meter to measure the amount of fuel combusted in the unit shall be installed, utilized and maintained. [District Rule 2201, 40 CFR 60.48(c)(g)]

- The permittee shall maintain daily records of the type and quantity of fuel combusted by the boiler. [District Rule 2201, 40 CFR 60.48(c)(g)]

Section 60.48c(i) states that all records required under this section shall be maintained by the owner or operator of the affected facility for a period of two years following the date of such record. District Rule 4306 requires that all records shall be kept for at least five years. Therefore, compliance is expected with this section.

Rule 4002 National Emissions Standards for Hazardous Air Pollutants (NESHAP)

Pursuant to Section 2.0, "All sources of hazardous air pollution shall comply with the standards, criteria, and requirements set forth therein". Therefore, the requirements of this rule apply to this facility. However, there are no applicable requirements for a non-major HAPs source.

As discussed under Rule 2550, NCPA is not a major HAP source; therefore, no actions are necessary to determine compliance with this rule.

Rule 4101 Visible Emissions

District Rule 4101, Section 5.0, indicates that no air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour, which is dark or darker than Ringelmann 1 or equivalent to 20% opacity. The following condition will be placed on each permit:

- No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

Compliance is expected with this Rule.

Rule 4102 Nuisance

Section 4.0 prohibits discharge of air contaminants, which could cause injury, detriment, nuisance or annoyance to the public. Public nuisance conditions are not expected as a result of operating the proposed boilers provided the equipment is well maintained. Therefore, compliance with this rule is expected. The following condition will be placed on each permit:

- No air contaminant shall be released into the atmosphere, which causes a public nuisance. [District Rule 4102]

California Health & Safety Code 41700

District Policy APR 1905 - Risk Management Policy for Permitting New and Modified Sources specifies that for an increase in emissions associated with a proposed new source or modification, the District perform an analysis to determine the possible impact to the nearest resident or worksite. The risk management review (RMR) summary is as follows:

Category	'-5-0	'-6-0	'-7-0	Project Total	Facility Total
Prioritization Score	2.31	0.00	1.40	3.71	3.71
Acute Hazard Index	0.02	N/A	0.05	0.07	0.07
Chronic Hazard Index	0.00	N/A	0.00	0.00	0.00
Maximum Individual Cancer Risk	4.57E-07	N/A	3.34E-07	7.91E-07	7.91E-07
T-BACT Required?	No	No	No		
Special Conditions Required?	No	No	No		

*The prioritization score was determined to be insignificant (less than 0.05); therefore, the effective prioritization score for this unit is considered to be 0.00.

N-2697-5-0

The acute and chronic indices are below 1.0; and the maximum individual cancer risk associated with the unit is 4.57E-07, which is less than 1.0 in a million threshold. In accordance with the District's Risk Management Policy, the unit is approved without toxic Best Available Control Technology (T-BACT).

N-2697-6-0

The prioritization score for this unit is not above 1.0. In accordance with the District's Risk Management Policy, the unit is approved without toxic Best Available Control Technology (T-BACT).

N-2697-7-0

The acute and chronic indices are below 1.0; and the maximum individual cancer risk associated with the unit is 3.34E-07, which is less than 1.0 in a million threshold. In accordance with the District's Risk Management Policy, the unit is approved without toxic Best Available Control Technology (T-BACT).

Please refer to Attachment F for health risk assessment.

California Health & Safety Code, Section 44300 (Air Toxic "Hot Spots")

Section 44300 of the California Health and Safety Code requires submittal of an air toxics "Hot Spot" information and assessment report for sources with criteria pollutant emissions greater than 10 tons per year. However, Section 44344.5 (b) states that a new facility shall not be required to submit such a report if all of the following conditions are met:

1. The facility is subject to a district permit program established pursuant to Section 42300.

2. The district conducts an assessment of the potential emissions or their associated risks, and finds that the emissions will not result in a significant risk.

3. The district issues a permit authorizing construction or operation of the new facility.

A health risk screening assessment was performed for the proposed project. The acute and chronic hazard indices are less than 1.0 and the cancer risk is less than ten (10) in a million, which are the thresholds of significance for toxic air contaminants. This project qualifies for exemption per the above exemption criteria.

Compliance is expected with this Rule.

Rule 4201 Particulate Matter Concentration

Section 3.0 prohibits discharge of dust, fumes, or total particulate matter into the atmosphere from any single source operation in excess of 0.1 grain per dry standard cubic foot.

N-2697-5-0

The exhaust flow rate at maximum load will be 1,044,503 acfm at 172°F. The moisture content in the exhaust is expected to be 8.3%. Therefore, the exhaust particulate matter emission concentration at 60°F is:

$$PM\left(\frac{gr}{dscf}\right) = \frac{\left(9.0\frac{lb-PM}{hr}\right)\left(7{,}000\frac{gr-PM}{lb-PM}\right)\left(\frac{hr}{60\ min}\right)}{\left(1{,}044{,}503\frac{ft^3}{min}\right)\left(\frac{460+60}{460+172}\right)(1-0.083)} = 0.001\frac{gr-PM}{dscf}$$

Since 0.001 gr/dscf is less than 0.1 gr/dscf, compliance is expected with this Rule.

N-2697-6-0

The exhaust flow rate is expected to be 185,280 acfm at 86°F. Moisture content is estimated to be 13%. Therefore, the exhaust particulate matter emission concentration at 60°F is:

$$PM\left(\frac{gr}{dscf}\right) = \frac{\left(0.45\frac{lb-PM}{hr}\right)\left(7{,}000\frac{gr-PM}{lb-PM}\right)\left(\frac{hr}{60\,min}\right)}{\left(185{,}280\frac{ft^3}{min}\right)\left(\frac{460+60}{460+86}\right)(1-0.13)} = 0.0003\frac{gr-PM}{dscf}$$

Since 0.0003 gr/dscf is less than 0.1 gr/dscf, compliance is expected with this Rule.

<u>N-2697-7-0</u>

F-Factor: 8,578 dscf/MMBtu at 60°F (natural gas)
PM_{10} Emission Factor: 0.0076 lb-PM_{10}/MMBtu (From Section VII.B)
Percentage of PM as PM_{10} in Exhaust: 100%

$$PM\left(\frac{gr}{dscf}\right) = \frac{\left(0.0076\frac{lb-PM}{hr}\right)\left(7{,}000\frac{gr-PM}{lb-PM}\right)\left(\frac{hr}{60\,min}\right)}{\left(8{,}578\frac{ft^3}{min}\right)} = 0.0062\frac{gr-PM}{dscf}$$

The following condition will be listed on each permit:

- Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

Compliance is expected with this Rule.

Rule 4301 Fuel Burning Equipment

The provisions of this rule shall apply to any fuel burning equipment except air pollution control equipment which is exempted according to Section 4.0. Fuel burning equipment is defined as any furnace, boiler, apparatus, stack, and all appurtenances thereto, used in the process of burning fuel for the primary purpose of producing heat or power by indirect heat transfer.

The requirements of section 5.0 are as follows:

- Combustion contaminates (TSP) - Not to exceed 0.1 gr/dscf @ 12% CO_2 and 10 lb/hr.
- SO_x emissions - Not to exceed 200 lb/hr
- NO_x emissions - Not to exceed 140 lb/hr

N-2697-5-0

CTG primarily produce power mechanically, i.e. the products of combustion pass directly across the turbine blades which causes the turbine shaft to rotate. The turbine shaft is coupled to an electrical generator shaft, which rotates and produces electricity. Because the CTG primarily produce power by mechanical means, it does not meet the definition of fuel burning equipment (stated above). Therefore, Rule 4301 does not apply to the affected equipment and no further discussion is required.

N-2697-6-0

This rule is not applicable to the proposed cooling tower.

N-2697-7-0

$$PM\left(\frac{gr}{dscf}\right) = \frac{PM\ Emissions\ \left(\frac{lb-PM}{MMBtu}\right)\times 7{,}000\ \frac{gr-PM}{lb-PM}}{F_{factor\ CO_2}\left(\frac{dscf}{MMBtu}\right)\times\left(\frac{100\%}{12\%}\right)}$$

$$= \frac{\left(0.0076\ \frac{lb-PM}{MMBtu}\right)\left(7{,}000\ \frac{gr-PM}{lb-PM}\right)}{\left(1{,}024.2\ \frac{dscf}{MMBtu}\right)\left(\frac{100\%}{12\%}\right)}$$

$$= 0.0062\ \frac{gr-PM}{dscf}$$

Per section VII.C.1 of this document, the emission rates are as follows:

PE = 0.55 lb-PM/hr (Percentage of PM as PM_{10} in Exhaust: 100%)
PE = 0.19 lb-SOx/hr
PE = 0.49 lb-NOx/hr

The proposed emissions are below the limits of this Rule; therefore, compliance is expected.

Rule 4304 Equipment Tuning Procedure for Boilers, Steam Generators and Process Heaters

Pursuant to District Rules 4305 and 4306, Section 6.3.1, the boiler is not required to be tuned since the company has proposed to use District approved Alternate Monitoring scheme "A" (District Policy SSP-1105) where the applicable emission limits are periodically monitored. Therefore, the proposed boiler is not subject to this rule.

Rule 4305 Boilers, Steam Generators and Process Heaters – Phase 2

Since the emission limits of District Rule 4306 and all other requirements are equivalent or more stringent than District Rule 4305 requirements, compliance with District Rule 4306 requirements will satisfy requirements of District Rule 4305.

Rule 4306 Boilers Steam Generators and Process Heaters – Phase 3

Applicability

This rule applies to any gaseous fuel or liquid fuel fired boiler, steam generator, or process heater with a total rated heat input greater than 5 million Btu per hour.

The proposed boiler is rated at a heat input rate of 65 MMBtu/hr. Therefore, this unit is subject to the requirements of this Rule.

NOx and CO Emission Limits

Section 5.1.1 requires that the proposed boiler shall emit less than or equal to 9.0 ppmvd NOx @ 3% O_2 and 400 ppmvd CO @ 3% O_2. NCPA has proposed to meet less than or equal to 7.0 ppmvd NOx @ 3% O_2 and 50 ppmvd CO @ 3% O_2. Therefore, compliance is expected with this section.

Section 5.2 lists the requirements for boilers limited to a heat input rate of less than 9 billion Btu per calendar year. This boiler is not limited to a heat input rate of less than 9 billion Btu per calendar year. Therefore, this section is not applicable to this unit.

Section 5.3 states that the NOx and CO emission limits shall not apply to this unit during start-up and shutdown period provided that the duration of each start-up or each shutdown is not greater than 2.0 hours, and the emission control system is utilized during these periods. The permittee may request more than 2.0 hours for each start-up or each shutdown as outlined under section 5.3.3. Per boiler manufacturers, low NOx burners achieve their rated emissions within one to two minutes of initial startup and do not require a special shutdown procedure. Because of the short duration before achieving the rated emissions following startup, the unit will be subject to the applicable emission limits of Sections 5.1 while in operation.

Monitoring Provisions

Section 5.4.1 requires the operator to install and maintain a non-resettable, totalizing mass or volumetric flow meter for the units which simultaneous uses gaseous and liquid fuels and are subject to the requirements of Section 5.1. NCPA is proposing to use gaseous fuel only. Therefore, they are not required to install and maintain the meter due to this section.

Section 5.4.2 requires monitoring of NOx, CO and O2 concentrations using CEMS, or an APCO approved alternate monitoring system. NCPA has proposed to use pre-approved alternate monitoring scheme "A" of District Policy SSP-1105, which requires periodic monitoring of NO_X, CO, and O_2 exhaust emissions concentrations, using a portable analyzer. The following conditions will be listed on the permit to ensure on-going compliance with NOx and CO emissions.

- The permittee shall monitor and record the stack concentration of NOx, CO and O2 at least once during each month in which source testing is not performed. NOx, CO and O2 monitoring shall be conducted utilizing a portable analyzer that meets District specifications given in District Policy SSP-1105. Monitoring shall not be required if unit is not in operation, i.e. the unit need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the unit(s) unless it has been performed within the last month. [District Rules 4305, 4306 and 4320]

- If the NOx or CO concentrations, as measured by the portable analyzer exceed the permitted emission levels, the permittee shall return the emissions to within the acceptable range as soon as possible, but no longer than 1 hour of operation after detection. If the portable analyzer show that emissions continue to exceed the allowable levels after 1 hour of operation following detection, the permittee shall notify the District within the following 1 hour and conduct a certified source test within 60 days of the first exceedance. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must then correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of the performing the notification and testing required by this condition. [District Rules 4305, 4306 and 4320]

- The permittee shall maintain records of: (1) permit number of the unit(s) operating during monitoring, (2) the date and time of NOx, CO and O2 measurements, (3) the O2 concentration in percent and the measured NOx and CO concentrations corrected to 3% O2, (4) make and model of exhaust gas analyzer, (5) exhaust gas analyzer calibration records, and (7) a description of any corrective action taken to maintain the emissions within the acceptable range. [District Rules 4305, 4306 and 4320]

<u>Compliance Determination</u>

Section 5.5.1 states the operator of any unit have the option of complying with either the applicable heat input (lb/MMBtu) emission limits or the concentration (ppmv) emission limit. NCPA has proposed to comply with the concentrations (ppmv) limit. Therefore, compliance is expected with this section.

Section 5.5.2 requires all emissions measurements shall be made with the unit operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. No determination of compliance shall be established within two hours after a continuous period in which fuel flow to the unit is shut off for 30 minutes or longer, or within 30 minutes after a re-ignition as defined in Section 3.0. Therefore, the following condition will be listed on the permit:

- All emissions measurements shall be made with the unit operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. No determination of compliance shall be established within two hours after a continuous period in which fuel flow to the unit is shut off for 30 minutes or longer, or within 30 minutes after a re-ignition as defined in Section 3.0 of District Rule 4306. [District Rules 4305, 4306 and 4320]

Section 5.5.3 states that all CEM data shall be averaged over a period of 15-consecutive minutes to demonstrate compliance with the applicable emission limits of this rule. NCPA is not proposing to use CEMS, rather they are proposing to use a portable analyzer on monthly basis. Therefore, they are not subject to the requirements of this section.

Section 5.5.4 requires emissions monitoring pursuant to Sections 5.4.2, 5.4.2.1, and 6.3.1 using a portable NO_X analyzer as part of an APCO approved Alternate Emissions Monitoring System, emission readings shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15-consecutive-minute sample reading or by taking at least five readings evenly spaced out over the 15-consecutive-minute period. The following condition will be listed on the permit:

- All alternate monitoring parameter emission readings shall be taken with the units operating either at conditions representative of normal operations or conditions specified in the permit-to-operate. The analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Emission readings taken shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive-minute sample reading or by taking at least five readings, evenly spaced out over the 15 consecutive-minute period. [District Rules 2201, 4305, 4306 and 4320]

Section 5.5.5 requires that for emissions source testing performed pursuant to Section 6.3.1 for the purpose of determining compliance with an applicable standard or numerical limitation of this rule, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit the test cannot be used to demonstrate compliance with an applicable limit. Therefore, the following permit condition will be listed on the permit as follows:

- For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit the test cannot be used to demonstrate compliance with an applicable limit. [District Rules 4305, 4306 and 4320]

Recordkeeping

Section 6.1 requires that the records required by Sections 6.1.1 through 6.1.3 shall be maintained for five calendar years and shall be made available to the APCO upon request. Failure to maintain records or information contained in the records that demonstrate noncompliance with the applicable requirements of this rule shall constitute a violation of this rule. The following condition will be listed on the permit:

- All records shall be maintained and retained on-site for a minimum of five years, and shall be made available for District inspection upon request. [District Rules 1070, 4305, 4306 and 4320]

Test Methods

Section 6.2 identifies the test methods for NOx, CO, O2 concentrations. The following conditions will be listed on each permit.

- Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]
- NOx emissions for source test purposes shall be determined using EPA Method 7E or CARB Method 100 on a ppmv basis. [District Rules 4305, 4306 and 4320]
- CO emissions for source test purposes shall be determined using EPA Method 10 or CARB Method 100. [District Rules 4305, 4306 and 4320]
- Stack gas oxygen (O2) shall be determined using EPA Method 3 or 3A or CARB Method 100. [District Rules 4305, 4306 and 4320]

Compliance Testing

Section 6.3.1 requires that this unit be tested to determine compliance with the applicable requirements of section 5.1 and 5.2.3 not less than once every 12 months. Upon demonstrating compliance on two consecutive compliance source tests, the following source test may be deferred for up to thirty-six months. The following permit conditions will be listed on the permit as follows:

- Source testing to measure NOx and CO emissions from this unit while fired on natural gas shall be conducted within 60 days of the end of commissioning period of the gas turbine system. [District Rules 2201, 4305, 4306 and 4320]

- Source testing to measure NOx and CO emissions from this unit while fired on natural gas shall be conducted at least once every twelve (12) months. After demonstrating compliance on two (2) consecutive annual source tests, the unit shall be tested not less than once every thirty-six (36) months. If the result of the 36-month source test demonstrates that the unit does not meet the applicable emission limits, the source testing frequency shall revert to at least once every twelve (12) months. [District Rules 4305, 4306 and 4320]
- The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

Section 6.3.2 lists compliance testing procedure for units that represent a group of units. NCPA will have only one boiler and they have proposed to test it in accordance with section 6.3.1. No further discussion is necessary.

<u>Emission Control Plan</u>

Section 6.4 requires that the operator of any unit shall submit to the APCO for approval an Emissions Control Plan according to the compliance schedule in Section 7.0 of District Rule 4306.

The permit application for the proposed boiler satisfies the requirements of the Emission Control Plan, as listed in Section 6.4 of District Rule 4306. No further discussion is necessary.

<u>Compliance Schedule</u>

Section 7.0 indicates that an operator with multiple units at a stationary source shall comply with this rule in accordance with the schedule specified in Table 2, Section 7.1 of District Rule 4306.

The unit will be in compliance with the emissions limits listed in Table 1, Section 5.1 of this rule, and periodic monitoring and source testing as required by District Rule 4306. Therefore, requirements of the compliance schedule, as listed in Section 7.1 of District Rule 4306, are satisfied. No further discussion is required.

Compliance is expected with this Rule.

Rule 4320 Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters greater than 5.0 MMBtu/hr

<u>Applicability</u>

Section 2.0 states that this rule applies to any gaseous fuel or liquid fuel fired boiler, steam generator, or process heater with a total rated heat input greater than 5 million Btu per hour.

The proposed boiler is rated at greater than 5 MMBtu/hr. Therefore, this unit is subject to the requirements of this Rule.

NOx, CO, PM Emission Limits

Section 5.1 states that an operator of a unit(s) subject to this rule shall comply with all applicable requirements of the rule and one of the following, on a unit-by-unit basis:

- Operate the unit to comply with the emission limits specified in Sections 5.2 and 5.4; or
- Pay an annual emissions fee to the District as specified in Section 5.3 and comply with the control requirements specified in Section 5.4; or
- Comply with the applicable Low-use Unit requirements of Section 5.5.

NCPA has chosen to operate the unit such that it would comply the emission limits specified in Section 5.2 and 5.4. These limits are summarized below:

NOx: 7.0 ppmvd @ 3% O_2
CO: 400 ppmvd @ 3% O_2
Particulate Matter: Use PUC-quality natural gas, commercial propane, butane, or LPG, or combination of such gases with fuel sulfur content of 5 grains/100 scf or less.

NCPA has proposed the following emission limits:

NOx: 7.0 ppmvd @ 3% O_2
CO: 400 ppmvd @ 3% O_2
Particulate Matter: Use PUC-regulated natural gas with fuel sulfur content of 1.0 grains/100 scf or less.

Compliance is expected with this section.

Section 5.6 states that the NOx and CO emission limits shall not apply to this unit during start-up and shutdown period provided that the duration of each start-up or each shutdown is not greater than 2.0 hours, and the emission control system is utilized during these periods. The permittee may request more than 2.0 hours for each start-up or each shutdown as outlined under section 5.6.3. Per boiler manufacturers, low NOx burners achieve their rated emissions within one to two minutes of initial startup and do not require a special shutdown procedure. Because of the short duration before achieving the rated emissions following startup, the unit will be subject to the applicable emission limits of Section 5.2 while in operation.

Monitoring Provisions

NOx, CO and O_2 monitoring provisions of this Rule are similar to that of Rule 4306. NCPA has proposed a monitoring scheme that complies with the requirements of this Rule. Thus, compliance is expected with this section.

Section 5.7.6 requires the operator to provide annual fuel sulfur content analysis. The following condition will be placed on the permit:

- The fuel sulfur content analysis shall be submitted to the District at least once every 12-month period. [District Rule 4320]
- Fuel sulfur content shall be determined using EPA Method 11 or EPA Method 15 or District, CARB and EPA approved alternative methods. [District Rule 4320]

Compliance Determination

Compliance determination requirements of this Rule are similar to that of Rule 4306. The permittee is required to demonstrate compliance with Rule 4306. Thus, compliance is expected with this section.

Recordkeeping

Recordkeeping requirements of this Rule are similar to that of Rule 4306. NCPA is required to keep all records for a period of at least five years. Thus, compliance is expected with this Rule.

Test Methods

Test Methods in this Rule are similar to the ones listed in Rule 4306. NCPA is expected to use these tests to demonstrate compliance with the proposed emission limits.

Compliance Testing

Compliance testing requirements of this Rule are similar to that of Rule 4306. Since the permittee is expected to demonstrate compliance with Rule 4306, compliance is expected with this section.

Emission Control Plan

Section 6.4 requires that no later than January 1, 2010, the operator of any unit shall submit to the APCO for approval an Emissions Control Plan according to the compliance schedule in Section 7.0.

The permit application for the proposed boiler satisfies the requirements of the Emission Control Plan, as listed in Section 6.4 of this Rule. No further discussion is necessary.

Compliance Schedule

The earliest compliance deadline to comply with the requirements of this Rule is July 1, 2010. The proposed boiler is expected to be operated in compliance with this Rule.

Compliance is expected with this Rule.

Rule 4351 Boilers Steam Generators and Process Heaters – Phase 1

This rule applies to boilers, steam generators, and process heaters at NO_x Major Sources that are not located west of Interstate 5 in Fresno, Kings, or Kern counties. This boiler will be located in the San Joaquin County. Therefore, compliance with this rule is expected.

Rule 4703 Stationary Gas Turbines

Applicability

Section 2.0 of this rule states that the provisions of this rule apply to all stationary gas turbine systems, which are subject to District permitting requirements, and with ratings equal to or greater than 0.3 megawatt (MW) or a maximum heat input rating of more than 3,000,000 Btu per hour, except as provided in Section 4.0.

NCPA has proposed to install a 255 MW gas turbine system. Therefore, the proposed system is subject to the requirements of this rule.

Section 5.1 – NO_X Emission Requirements

Section 5.1.1 (Tier 1) of this rule limits the NO_X emissions from stationary gas turbine system greater than 10 MW, and equipped with Selective Catalytic Reduction (SCR). Since the proposed turbine will meet more stringent Tier 2 emission requirements in Section 5.1.2, compliance with this section is assured.

Section 5.1.2 (Tier 2) of this rule limits the NO_X emissions from combined cycle, stationary gas turbine system rated at greater than 10 MW to 5 ppmv @ 15% O_2 (Standard Option) and 3 ppmv @ 15% O_2 (Enhanced Option). Section 7.2.1 (Table 7-1) sets a compliance date of April 30, 2004 for the Standard Option and Section 7.2.4 sets a compliance date of April 30, 2008 for the Enhanced Option. As discussed above, the proposed turbine system will be limited to 2.0 ppmv @ 15% O_2 (based on a 1-hour average); therefore compliance with this section is expected. The following conditions will be placed on the permit:

- Except during startup and shutdown periods, emissions from the gas turbine system with duct burner firing shall not exceed any of the following limits: NOx (as NO2) – 15.25 lb/hr and 2.0 ppmvd @ 15% O2; CO – 13.93 lb/hr and 3 ppmvd @ 15% O2; VOC (as methane) – 5.32 lb/hr and 2.0 ppmvd @ 15% O2; PM10 – 11.00 lb/hr; or SOx (as SO2) – 6.00 lb/hr. NOx (as NO2) emission limits are based on 1-hour rolling average period. All other emission limits are based on 3-hour rolling average period. [District Rules 2201, 4001, and 4703]

- Except during startup and shutdown periods, emissions from the gas turbine system with no duct burner firing shall not exceed any of the following limits: NOx (as NO2) – 13.64 lb/hr and 2.0 ppmvd @ 15% O2; CO – 12.46 lb/hr and 3 ppmvd @ 15% O2;

VOC (as methane) – 3.33 lb/hr and 1.4 ppmvd @ 15% O2; PM10 – 9.00 lb/hr; or SOx (as SO2) – 5.37 lb/hr. NOx (as NO2) emission limits are based on 1-hour rolling average period. All other emission limits are based on 3-hour rolling average period. [District Rules 2201, 4001, and 4703]

Section 5.2 – CO Emission Requirements

Per Table 5-4 of section 5.2, the CO emissions concentration from the proposed gas turbine system (General Electric Frame 7) must be less than 25 ppmvd @ 15% O_2. Rule 4703 does not include a specific averaging period requirement for demonstrating compliance with the CO emission limit. The District practice is to require CO emissions compliance demonstration on 3-hour rolling average period.

NCPA has proposed to emit less than or equal to 3 ppmvd CO @ 15% O_2 on 3-hour rolling average period. Thus, compliance is expected with this section. Refer to the conditions shown in Section 5.1.2 (above).

Section 5.3 – Transitional Operation Periods

This section states that the emission limit requirements of Sections 5.1.1, 5.1.2 or 5.2 shall not apply during a transitional operation period, which includes bypass transition period, primary re-ignition period, reduced load period, start-up or shutdown (each term is defined in Section 3.0 of Rule 4703), provided an operator complies with the requirements of section 5.3.1 which are outlined below:

5.3.1.1 The duration of each startup or each shutdown shall not exceed two hours.
5.3.1.2 For each bypass transition period, the requirements specified in Section 3.2 shall be met.
5.3.1.3 For each primary re-ignition period, the requirements specified in Section 3.20 shall be met.
5.3.1.4 Each reduced load period shall not exceed one hour.

NCPA has proposed to incorporate startup and shutdown provisions into the operating requirements for the proposed gas turbine system. They have proposed that the duration of combined startup and shutdown events will last no more than six hours per day. Assuming a maximum of one startup and one shutdown in a given day, section 5.3.1.1 would have allowed them a maximum of four hours per day. Since the proposed duration exceeds four hours, the facility must meet the requirements of Section 5.3.3.

Section 5.3.1.2 requires the operator to meet the requirements of Section 3.2 for each bypass transition period.

Per NCPA's consultant, the exhaust from the CTG is vented into the HRSG. There is no bypass exhaust stack. Therefore, this turbine system is not required to meet any bypass transition period requirements.

Section 5.3.1.3 requires the permittee to meet the requirements in Section 3.20 for each primary re-ignition period. Section 3.20 defines the primary re-ignition period and requires the following:

- The duration of a primary re-ignition shall not exceed one hour
- NOx emissions shall not exceed 15 ppmvd @ 15% O_2, average over one-hour
- CO emissions shall not exceed 25 ppmvd @ 15% O_2

Per NCPA's consultant, they will comply with these limits. The following condition will be listed on the permit:

- The primary re-ignition period shall be defined as the duration of time during which a gas turbine is operated at less than rated capacity in order to reset the dry low-NOx combustion system following a primary re-ignition provided that all of the following are met: 1) the duration of a primary re-ignition period shall not exceed one hour; 2) NOx emissions shall not exceed 15 ppmvd, corrected to 15% O2, averaged over one hour; and 3) CO emissions shall not exceed 25 ppmvd, corrected to 15% O2. [District Rule 4703, 5.3.1.3, 3.20]

Section 5.3.1.4 requires that each reduced load period shall not exceed one hour. The following condition will be listed on the permit:

- Reduced load period is defined as the time during which a gas turbine is operated at less than rated capacity in order to change the position of the exhaust gas diverter gate. Each reduced load period shall not exceed one hour. [District Rule 4703, 5.3.1.4 and 3.23]

Section 5.3.2 requires that emission control system shall be in operation and emissions shall be minimized insofar as technologically feasible during each transitional period (in this case it would be startup, shutdown, reduced load period and primary re-ignition period). The following condition will be listed on the permit:

- The emission control systems shall be in operation and emissions shall be minimized insofar as technologically feasible during startup and shutdown. [District Rule 4703, 5.3.2]

Section 5.3.3 states that at a minimum, a justification for the increased duration shall include the following:

A clear identification of the control technologies or strategies to be utilized; and

The control technologies and strategies to be utilized to minimize emissions during the startup period are as follows:

- "Rapid Response" technology, including an auxiliary boiler to preheat fuel and provide steam turbine sealing steam prior to CTG startup
- Dry low-NOx combustors in the CTG
- Oxidation catalyst in the HRSG
- SCR in the HRSG
- Good combustion practices
- Upon startup, the ammonia injection upstream of the SCR catalyst will be started as soon as the catalyst and ammonia injection system warm to their minimum operating temperatures as specified by the SCR vendor

A description of what physical conditions prevail during the period that prevent the controls from being effective; and

The combined-cycle equipment startup duration depends on how fast the high pressure steam drum and the steel walls of the steam turbine can be warmed to operating temperature without generating stress cracks or otherwise damaging the equipment. During a cold startup, in which the *CTG/HRSG* have been shut down for more than 72 hours, the HRSG and steam turbine parts are at ambient temperature and there is a great deal of thermal mass that must be heated. Once the high-pressure steam drum is heated, steam developed in the HRSG from the heated turbine exhaust is admitted into the steam turbine at a controlled temperature to heat it as rapidly as possible without causing stress cracking. The steam temperature is controlled by limiting the load on the gas turbine. At the lower load points, the gas turbine is tuned for combustion stability and not for emissions performance, so uncontrolled emissions at low loads are much higher than uncontrolled emissions at typical operating loads (above about 50%). The allowable rate of temperature increase at the steam turbine is the limiting factor in determining how quickly the gas turbine can achieve higher loads. This, in turn, limits how quickly the gas turbine combustor can be brought up to this minimum load point and this latter step is necessary for the unit to be able to comply with the limits of Rule 4703.

A reasonably precise estimate as to when the physical conditions will have reached a state that allows for the effective control of emissions; and

Startup information provided by the turbine and HRSG vendors indicates that for a cold startup, a minimum of 4 hours is required for the unit to come into compliance with the limits of Rule 4703. Per consultant, the experience at other combined cycle gas turbine power plants has shown that up to 6 hours may be required under some circumstances. Because NCPA is proposing to use "Rapid Response" technology for this project, it is expected that startups of the proposed CTG will be shorter than those experienced for other projects. The Rapid Response package, which includes a modified HRSG design and an auxiliary boiler, is designed to allow faster heating of the HRSG and earlier startup of the steam turbine, significantly reducing startup times. However, because no Rapid Response configuration plants have yet been built or operated, no in-use operating data are yet available to allow observation and evaluation of the actual times required for a unit to come into compliance during a startup. Therefore, NCPA is conservatively assuming that the times required for startups will be the same as those for conventional Frame 7-based combined cycle turbine plants.

A detailed list of activities to be performed during the period and a reasonable explanation for the length of time needed to complete each activity; and

The facility has provided the District with a detailed list of activities to be performed during the period and a reasonable explanation for the length of time needed to complete each activity.

A description of the material process flow rates and system operating parameters, etc., the operator plans to evaluate during the process optimization; and an explanation of how the activities and process flow affect the operation of the emissions control equipment; and

The startup duration depends on the allowable ramp rate of the steam temperature to the steam turbine, which depends on the acceptable rate of increase of the metal temperature of the hot reheat and HP steam bowls at the steam turbine inlets. The maximum steam temperature is set by applying an allowable differential above the metal temperature. The differential is determined by the steam turbine supplier, and is imposed by the supplier's control system to avoid damage to the steam turbine from thermal stress. The control system limits gas turbine load to control the steam temperature. Any manual override of the gas turbine load limit by the operator reduces the life expectancy of the steam turbine.

In addition, the time prior to initiation of ammonia flow to the SCR system depends on the temperature of the SCR catalyst. The catalyst bed is warmed by the exhaust flow from the gas turbine. The total mass of metal and water in the HRSG tubes, piping, and drums removes heat from the gas turbine exhaust as it warms. This extends the time required to heat the SCR catalyst to the minimum temperature at which ammonia may be injected upstream of the catalyst bed to begin reducing NOx to N2. The steam turbine and SCR catalyst temperatures are all monitored by the plant control system, and the turbine ramp rate and SCR initiation sequence are governed by the equipment/system manufacturer's recommended procedures.

The basis for the requested additional duration

The description of activities above demonstrate that the minimum time required for a cold startup of the plant as currently configured is approximately 4 hours. This startup time is contingent upon all of the activities being performed in time to support subsequent activities. Any delay in preparation of the supporting systems will result in a corresponding delay in startup and/or loading of the gas turbines. To be confident that the startup time allowed is adequate and will not be exceeded, two hours are added to the minimum startup time to account for possible delays.

Since the facility has demonstrated compliance and provided all the information required by Section 5.3.3.2, the proposed increase in startup and shutdown emissions is compliant with District Rule 4703. The following conditions will ensure compliance with the requirements section 5.3.1.1:

- During start-up and shutdown periods, the emissions shall not exceed any of the following limits: NO_X (as NO_2) – 160.00 lb/hr; CO – 900.00 lb/hr; VOC (as methane) – 16.00 lb/hr; PM_{10} – 9.00 lb/hr; SO_X (as SO_2) – 5.37 lb/hr; or NH_3 – 25.25 lb/hr. [District Rules 2201 and 4703]

- Start-up is defined as the period of time during which a unit is brought from a shutdown status to its operating temperature and pressure, including the time required by the unit's emission control system to reach full operation. [District Rule 4703, 3.29]

- Shutdown is defined as the period of time during which a unit is taken from an operational to a non-operational status by allowing it to cool down from its operating temperature to ambient temperature as the fuel supply to the unit is completely turned off. [District Rule 4703, 3.26]

- The duration of combined startup and shutdown period shall not exceed six hours in any one day. [District Rules 2201 and 4703]

<u>Section 6.2 - Monitoring and Recordkeeping</u>

Section 6.2.1 requires the owner to operate and maintain continuous emissions monitoring equipment for NO_X and oxygen, or install and maintain APCO-approved alternate monitoring. As discussed earlier in this evaluation, NCPA has proposed to operate a Continuous Emissions Monitoring System (CEMS) that will monitors NO_X and oxygen content in the exhaust stack. Therefore, the requirements of this section have been satisfied. The following condition will ensure continued compliance with the requirements of this section:

- The owner or operator shall install, certify, maintain, operate, and quality-assure a continuous emission monitor system (CEMS) which continuously measures and records the exhaust gas NOx, CO, and O2 concentrations. Continuous emissions monitors shall be capable of monitoring emissions during normal operating conditions and during startups and shutdowns, provided that CEMS passes the relative accuracy requirement listed in 40 CFR Part 60, Appendix B, Performance

Specification 2 (PS-2). If relative accuracy of CEMS cannot be demonstrated during the startup, CEMS results during startup and shutdown events shall be replaced with startup emission rates obtained from the source test to determine compliance with emission limits contained in this document. [District Rules 1080, 2201 and 4703, 40 CFR 60.4340(b)(1) and 40 CFR 60.4345(a)]

Section 6.2.2 specifies monitoring requirements for turbines without exhaust-gas NO_X control devices. The proposed gas turbine system will be equipped with an SCR system that is designed to control NO_X emissions. Therefore, the requirements of this section are not applicable and no further discussion is required.

Section 6.2.3 requires that for units 10 MW and greater that operated an average of more than 4,000 hours per year over the last three years before August 18, 1994, the owner or operator shall monitor the exhaust gas NO_X emissions. The proposed turbine was not in operation prior to August 18, 1994 and the requirements of this section are not applicable. No further discussion is required.

Section 6.2.4 requires the facility to maintain all records for a period of five years from the date of data entry and shall make such records available to the APCO upon request. NCPA will be required to maintain all records for at least five years and make them available to the APCO upon request. Therefore, the proposed turbines will be operating in compliance with the five year recordkeeping requirements of this rule. The following condition will placed on the permit:

- The owner or operator shall maintain all records of required monitoring data and support information for a period of five years from the date of data entry and shall make such records available to the District upon request. [District Rules 2201 and 4703, 6.2.4]

Section 6.2.5 requires that the owner or operator shall submit to the APCO, before issuance of the Permit to Operate, information correlating the control system operating to the associated measure NO_X output. This information may be used by the APCO to determine compliance when there is no continuous emission monitoring system for NO_X available or when the continuous emissions monitoring system is not operating properly. The following condition will be placed on the permit:

- The owner or operator shall submit to the District information correlating the NO_X control system operating parameters to the associated measured NO_X output. The information must be sufficient to allow the District to determine compliance with the NO_X emission limits of this permit when the CEMS is not operating properly. [District Rule 4703, 6.2.5]

Section 6.2.6 requires the owner or operator to maintain a stationary gas turbine system operating log that includes, on a daily basis, the actual local startup and stop time, length and reason for reduced load periods, total hours of operation, and the type and quantity of fuel used.

Section 6.2.7 requires the owner or operator shall maintain a stationary gas turbine system log for units exempt under Section 4.2 of this Rule. NCPA's gas turbine system is not exempt under Section 4.2 of this Rule. Therefore, no further discussion is required.

Section 6.2.8 requires the operator performing start-up or shutdown of a unit shall keep records of the duration of start-up or shutdown.

Section 6.2.11 requires the operator of a unit shall keep records of the date, time and duration of each bypass transition period and each primary re-ignition period.

NCPA will be required to maintain records of the items listed in above applicable sections. The following conditions will be placed on the permit:

- The owner or operator shall maintain a stationary gas turbine system operating log that includes, on a daily basis, the actual local startup and stop time, length and reason for reduced load periods, total hours of operation, the type and quantity of fuel used, duration of start-up, duration of shutdown, date/time and duration of each primary re-ignition period. [District Rule 4703, 6.26, 6.28, 6.2.11]

Sections 6.3 and 6.4 - Compliance Testing

Section 6.3.1 states that the owner or operator of any stationary gas turbine system subject to the provisions of Section 5.0 of this rule shall provide source test information annually regarding the exhaust gas NO_X and CO concentrations. The gas turbine system proposed by NCPA is subject to the provisions of Section 5.0 of this rule. Therefore, this system is required to be tested annually to ensure compliance with NO_X and CO concentrations. The following condition will be placed on the permit:

- Source testing to determine compliance with the NOx, CO, VOC and NH3 emission rates (lb/hr and ppmvd @ 15% O_2) and PM_{10} emission rate (lb/hr) shall be conducted within 60 days after the end of commissioning period and at least once every 12 months thereafter. [District Rules 2201 and 4703, 40 CFR 60.4400(a)]

Section 6.3.2 specifies source testing requirements for units operating less than 877 hours per year. As discussed above, the proposed turbine system will be allowed to operate in excess of 877 hours per year. Therefore, the requirements of this section are not applicable and no further discussion is required.

Section 6.3.3 states that units with intermittently operated auxiliary burners shall demonstrate compliance with the auxiliary burner in both "on" and "off" configurations. The following condition will ensure continued compliance with the requirements of this section:

- Compliance with the NO_X and CO emission limits shall be demonstrated with the auxiliary burner both on and off configurations. [District Rule 4703, 6.3.3]

Section 6.4 states that the facility must demonstrate compliance annually with the NO_X and CO emission limits using the following test methods, unless otherwise approved by the APCO and EPA:

- Oxides of nitrogen emissions for compliance tests shall be determined by using EPA Method 7E or EPA Method 20.

- Carbon monoxide emissions for compliance tests shall be determined by using EPA Test Methods 10 or 10B.

- Oxygen content of the exhaust gas shall be determined by using EPA Methods 3, 3A, or 20.

- HHV and LHV of gaseous fuels shall be determined by using ASTM D3588-91, ASTM 1826-88, or ASTM 1945-81.

The following condition will ensure continued compliance with the test method requirements of this section:

- The following test methods shall be used: NO_X - EPA Method 7E or 20 or CARB Method 100; CO - EPA Method 10 or 10B or CARB Method 100; VOC - EPA Method 18 or 25; PM10 - EPA Method 5 (front half and back half) or 201 and 202a; ammonia - BAAQMD ST-1B; and O_2 - EPA Method 3, 3A, or 20 or CARB Method 100. EPA approved alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4703 and 40 CFR 60.4400(1)(i)]

Compliance is expected with this Rule.

Rule 4801 Sulfur Compounds

Section 3.1 states that a person shall not discharge into the atmosphere sulfur compounds, which would exist as a liquid or gas at standard conditions, exceeding a concentration of two-tenths (0.2) percent by volume calculated as sulfur dioxide (SO_2) at the point of discharge on a dry basis averaged over 15 consecutive minutes.

For the proposed gaseous fuel combustion at a reference state of 60 °F, the Rule 4801 limit of 2,000 ppmvd is equivalent to:

$$\frac{(2000\ \text{ppmvd})\left(8{,}578\dfrac{\text{dscf}}{\text{MMBtu}}\right)\left(64\dfrac{\text{lb}-\text{SO}_x}{\text{lb}-\text{mol}}\right)}{\left(379.5\dfrac{\text{dscf}}{\text{lb}-\text{mol}}\right)\left(10^6\right)} \cong 2.9\frac{\text{lb}-\text{SO}_x}{\text{MMBtu}}$$

SO_x emissions from proposed CTG and the auxiliary boiler are based on 1.0 gr-S/100 scf, equivalent to 0.00285 lb/MMBtu. Since these emissions are less than 2.9 lb/MMBtu, it is expected that each unit will operate in compliance with this Rule.

Rule 7012 Hexavalent Chromium – Cooling Towers

The requirements of this rule shall apply to any person who owns or operates or who plans to build, own, or operate a cooling tower in which the circulating water is exposed to the atmosphere.

Section 5.2.1 of this rule states no hexavalent chromium containing compounds shall be added to cooling tower circulating water. The following condition will be placed on permit N-2697-6-0:

- No hexavalent chromium containing compounds shall be added to cooling tower circulating water. [District Rule 7012]

Compliance is expected with this Rule.

Rule 8011 General Requirements
Rule 8021 Construction, Demolition, Excavation, Extraction And Other Earthmoving Activities
Rule 8031 Bulk Materials
Rule 8041 Carryout And Trackout
Rule 8051 Open Areas
Rule 8061 Paved and Unpaved Roads
Rule 8071 Unpaved Vehicle/Equipment Traffic Areas

The construction of this new facility will involve excavation, extraction, construction, demolition, outdoor storage piles, paved and unpaved roads.

The regulations from the 8000 Series District Rules contain requirements for the control of fugitive dust. These requirements apply to various sources, including construction, demolition, excavation, extraction, mining activities, outdoor storage piles, paved and unpaved roads. Compliance with these regulations will be required by the following permit conditions, which will be listed on each permit as follows:

- Disturbances of soil related to any construction, demolition, excavation, extraction, or other earthmoving activities shall comply with the requirements for fugitive dust control in District Rule 8021 unless specifically exempted under Section 4.0 of Rule 8021 or Rule 8011. [District Rules 8011 and 8021]

- An owner/operator shall submit a Dust Control Plan to the APCO prior to the start of any construction activity on any site that will include 10 acres or more of disturbed surface area for residential developments, or 5 acres or more of disturbed surface area for non-residential development, or will include moving, depositing, or relocating more than 2,500 cubic yards per day of bulk materials on at least three days. [District Rules 8011 and 8021]

- An owner/operator shall prevent or cleanup any carryout or trackout in accordance with the requirements of District Rule 8041 Section 5.0, unless specifically exempted under Section 4.0 of Rule 8041 (8/19/04) or Rule 8011(8/19/04). [District Rules 8011 and 8021]

- Whenever open areas are disturbed, or vehicles are used in open areas, the facility shall comply with the requirements of Section 5.0 of District Rule 8051, unless specifically exempted under Section 4.0 of Rule 8051 or Rule 8011. [District Rules 8011 and 8051]

- Any paved road or unpaved road shall comply with the requirements of District Rule 8061 unless specifically exempted under Section 4.0 of Rule 8061 or Rule 8011. [District Rules 8011 and 8061]

- Water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure shall be applied to unpaved vehicle travel areas as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

- Where dusting materials are allowed to accumulate on paved surfaces, the accumulation shall be removed daily or water and/or chemical/organic dust stabilizers/suppressants shall be applied to the paved surface as required to maintain continuous compliance with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011 and limit Visible Dust Emissions (VDE) to 20% opacity. [District Rule 8011 and 8071]

- On each day that 50 or more Vehicle Daily Trips or 25 or more Vehicle Daily Trips with 3 axles or more will occur on an unpaved vehicle/equipment traffic area, permittee shall apply water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

- Whenever any portion of the site becomes inactive, Permittee shall restrict access and periodically stabilize any disturbed surface to comply with the conditions for a stabilized surface as defined in Section 3.58 of District Rule 8011. [District Rules 8011 and 8071]

- Records and other supporting documentation shall be maintained as required to demonstrate compliance with the requirements of the rules under Regulation VIII only for those days that a control measure was implemented. Such records shall include the type of control measure(s) used, the location and extent of coverage, and the date, amount, and frequency of application of dust suppressant, manufacturer's dust suppressant product information sheet that identifies the name of the dust suppressant and application instructions. Records shall be kept for one year following project completion that results in the termination of all dust generating activities. [District Rules 8011, 8031, and 8071]

California Environmental Quality Act (CEQA)

The California Environmental Quality Act (CEQA) requires each public agency to adopt objectives, criteria, and specific procedures consistent with CEQA Statutes and the CEQA Guidelines for administering its responsibilities under CEQA, including the orderly evaluation of projects and preparation of environmental documents. The San Joaquin Valley Unified Air Pollution Control District (District) adopted its *Environmental Review Guidelines* (ERG) in 2001. The basic purposes of CEQA are to:

- Inform governmental decision-makers and the public about the potential, significant environmental effects of proposed activities.
- Identify the ways that environmental damage can be avoided or significantly reduced.
- Prevent significant, avoidable damage to the environment by requiring changes in projects through the use of alternatives or mitigation measures when the governmental agency finds the changes to be feasible.
- Disclose to the public the reasons why a governmental agency approved the project in the manner the agency chose if significant environmental effects are involved.

The California Energy Commission (CEC) has the exclusive power to certify all thermal electric power plants greater than 50 MW in the State of California (Public Resources Code § 25500). While the CEC siting process is exempt from CEQA (14 CCR § 15251(k)), it is functionally equivalent to CEQA.

The District holds no discretionary approval powers over this project; however the District prepares a Determination of Compliance (DOC), this document. The DOC confers the rights and privileges of an Authority to Construct upon certification by the CEC, where the CEC certificate contains the conditions set forth in this DOC (20 CCR § 1744.5 and Rule 2201 § 5.8.8). A Permit to Operate is required to be issued if the project receives a certificate from the CEC and the project is constructed in accordance with the conditions set forth in the DOC (Rule 2201 § 5.8.9). The District makes the following findings regarding this project: the District holds no discretionary approval powers over this project and the District's actions are ministerial (CEQA Guidelines § 15369).

40 CFR Part 51 Appendix S Requirements for $PM_{2.5}$

40 CFR 51 Appendix S requirements are applicable to new major $PM_{2.5}$ sources and federal major modifications for $PM_{2.5}$. The significance thresholds are as follows:

$PM_{2.5}$ major source threshold	100 ton/year
$PM_{2.5}$ federal major modification threshold	10 ton/year

As discussed in Section VII.D.2 of this document, this facility is not a Major Source for PM_{10} emissions. As $PM_{2.5}$ is a subset of PM_{10}, and the $PM_{2.5}$ Major Source threshold is greater than the PM_{10} Major Source threshold, this facility is not a Major Source for $PM_{2.5}$ emissions. Therefore, Appendix S requirements for $PM_{2.5}$ are not applicable and no further discussion is required.

IX. RECOMMENDATION

ATCs should be issued after addressing comments from the public, CARB, EPA and the NCPA.

X. BILLING INFORMATION

ATC Permit	Fee Schedule	Fee Description	Previous Fee Schedule
N-2697-5-0	3020-08B-H	255,000 kW Electric Generation Plant	None
N-2697-6-0	999-99	Component of an Electric Generation Plant	None
N-2697-7-0	3020-02-H	65 MMBtu/hr, Boiler	None

ATTACHMENT A
PDOC CONDITIONS

San Joaquin Valley
Air Pollution Control District

AUTHORITY TO CONSTRUCT

PERMIT NO: N-2697-5-0 **ISSUANCE DATE:** DRAFT

LEGAL OWNER OR OPERATOR: NORTHERN CALIFORNIA POWER
MAILING ADDRESS: 651 COMMERCE DR
ROSEVILLE, CA 95678

LOCATION: 12751 N THORNTON RD
LODI, CA 95241

EQUIPMENT DESCRIPTION:
255 MW (NOMINAL) COMBINED-CYCLE ELECTRIC GENERATION PLANT CONSISTING OF A GENERAL ELECTRIC INDUSTRIAL FRAME "RAPID RESPONSE" 7FA (OR EQUIVALENT) NATURAL GAS-FIRED TURBINE ENGINE WITH DRY LOW-NOX COMBUSTORS, A HEAT RECOVERY STEAM GENERATOR EQUIPPED WITH 222 MMBTU/HOUR NATURAL GAS-FIRED DUCT BURNER SERVED BY A SELECTIVE CATALYTIC REDUCTION WITH AMMONIA INJECTION AND AN OXIDIZATION CATALYST AND A STEAM TURBINE GENERATOR

CONDITIONS

1. The permittee shall not begin actual on-site construction of the equipment authorized by this Authority to Construct until the lead agency satisfies the requirements of the California Environmental Quality Act (CEQA). [California Environmental Quality Act]
2. The permittee shall submit an application to comply with SJVUAPCD District Rule 2540 - Acid Rain Program. [District Rule 2540]
3. {1830} This Authority to Construct serves as a written certificate of conformity with the procedural requirements of 40 CFR 70.7 and 70.8 and with the compliance requirements of 40 CFR 70.6(c). [District NSR Rule] Federally Enforceable Through Title V Permit
4. {1831} Prior to operating with modifications authorized by this Authority to Construct, the facility shall submit an application to modify the Title V permit with an administrative amendment in accordance with District Rule 2520 Section 5.3.4. [District Rule 2520, 5.3.4] Federally Enforceable Through Title V Permit
5. The owner or operator shall notify the District of any breakdown condition as soon as reasonably possible, but no later than one hour after its detection, unless the owner or operator demonstrates to the District's satisfaction that the longer reporting period was necessary. [District Rule 1100]

CONDITIONS CONTINUE ON NEXT PAGE

YOU MUST NOTIFY THE DISTRICT COMPLIANCE DIVISION AT (209) 557-6400 WHEN CONSTRUCTION IS COMPLETED AND PRIOR TO OPERATING THE EQUIPMENT OR MODIFICATIONS AUTHORIZED BY THIS AUTHORITY TO CONSTRUCT. This is NOT a PERMIT TO OPERATE. Approval or denial of a PERMIT TO OPERATE will be made after an inspection to verify that the equipment has been constructed in accordance with the approved plans, specifications and conditions of this Authority to Construct, and to determine if the equipment can be operated in compliance with all Rules and Regulations of the San Joaquin Valley Unified Air Pollution Control District. Unless construction has commenced pursuant to Rule 2050, this Authority to Construct shall expire and application shall be cancelled two years from the date of issuance. The applicant is responsible for complying with all laws, ordinances and regulations of all other governmental agencies which may pertain to the above equipment.

Seyed Sadredin, Executive Director / APCO

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DAVID WARNER, Director of Permit Services

N-2697-5-0 : Apr 13 2009 12:02PM – KAHLONJ : Joint Inspection Required with KAHLONJ

6. The District shall be notified in writing within ten days following the correction of any breakdown condition. The breakdown notification shall include a description of the equipment malfunction or failure, the date and cause of the initial failure, the estimated emissions in excess of those allowed, and the methods utilized to restore normal operations. [District Rule 1100]
7. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
8. Particulate matter emissions from the gas turbine system shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201] Federally Enforceable Through Title V Permit
9. No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101] Federally Enforceable Through Title V Permit
10. APCO or an authorized representative shall be allowed to inspect, as determined to be necessary, the required monitoring devices to ensure that such devices are functioning properly. [District Rule 1080] Federally Enforceable Through Title V Permit
11. Commissioning activities are defined as, but not limited to, all testing, adjustment, tuning, and calibration activities recommended by the equipment manufacturers and the construction contractor to ensure safe and reliable steady state operation of the gas turbine and associated electrical delivery systems. [District Rule 2201]
12. Commissioning period shall commence when all mechanical, electrical, and control systems are installed and individual system startup has been completed, or when a gas turbine is first fired, whichever occurs first. The commissioning period shall terminate when the plant has completed initial source testing, completed final plant tuning, and is available for commercial operation. [District Rule 2201]
13. During the commissioning period, emission rates from the gas turbine system shall not exceed any of the following limits: NOx (as NO2) - 400.00 lb/hr and 4,000 lb/day; VOC (as CH4) - 16.00 lb/hr and 160.0 lb/day; CO - 2,000 lb/hr and 20,000 lb/day; PM10 - 11.00 lb/hr and 108.0 lb/day; or SOx (as SO2) - 6.00 lb/hr and 70.1 lb/day. [District Rule 2201] Federally Enforceable Through Title V Permit
14. During commissioning period, NOx and CO emission rate shall be monitored using installed and calibrated CEMS. [District Rule 2201] Federally Enforceable Through Title V Permit
15. The total mass emissions of NOx, VOC, CO, PM10 and SOx that are emitted during the commissioning period shall accrue towards the quarterly emission limits. [District Rule 2201] Federally Enforceable Through Title V Permit
16. During commissioning period, the owner or operator shall keep records of the natural gas fuel combusted in the gas turbine system on daily basis. [District Rule 2201] Federally Enforceable Through Title V Permit
17. During start-up and shutdown periods, the emissions shall not exceed any of the following limits: NOx (as NO2) - 160.00 lb/hr; CO - 900.00 lb/hr; VOC (as methane) - 16.00 lb/hr; PM10 - 9.00 lb/hr; SOx (as SO2) - 5.37 lb/hr; or Ammonia (NH3) - 25.25 lb/hr. [District Rule 2201] Federally Enforceable Through Title V Permit
18. Start-up is defined as the period of time during which a unit is brought from a shutdown status to its operating temperature and pressure, including the time required by the unit's emission control system to reach full operation. [District Rule 4703, 3.29] Federally Enforceable Through Title V Permit
19. Shutdown is defined as the period of time during which a unit is taken from an operational to a non-operational status by allowing it to cool down from its operating temperature to ambient temperature as the fuel supply to the unit is completely turned off. [District Rule 4703, 3.26] Federally Enforceable Through Title V Permit
20. The emission control systems shall be in operation and emissions shall be minimized insofar as technologically feasible during startup and shutdown. [District Rule 4703, 5.3.2] Federally Enforceable Through Title V Permit
21. The duration of combined startup and shutdown period shall not exceed six hours in any one day. [District Rules 2201 and 4703] Federally Enforceable Through Title V Permit

CONDITIONS CONTINUE ON NEXT PAGE

22. Except during startup and shutdown periods, emissions from the gas turbine system with duct burner firing shall not exceed any of the following limits: NOx (as NO2) - 15.25 lb/hr and 2.0 ppmvd @ 15% O2; CO - 13.93 lb/hr and 3 ppmvd @ 15% O2; VOC (as methane) - 5.32 lb/hr and 2.0 ppmvd @ 15% O2; PM10 - 11.00 lb/hr; or SOx (as SO2) - 6.00 lb/hr. NOx (as NO2) emission limits are based on 1-hour rolling average period. All other emission limits are based on 3-hour rolling average period. [District Rules 2201, 4001 and 4703] Federally Enforceable Through Title V Permit

23. Except during startup and shutdown periods, emissions from the gas turbine system with no duct burner firing shall not exceed any of the following limits: NOx (as NO2) - 13.64 lb/hr and 2.0 ppmvd @ 15% O2; CO - 12.46 lb/hr and 3 ppmvd @ 15% O2; VOC (as methane) - 3.33 lb/hr and 1.4 ppmvd @ 15% O2; PM10 - 9.00 lb/hr; or SOx (as SO2) - 5.37 lb/hr. NOx (as NO2) emission limits are based on 1-hour rolling average period. All other emission limits are based on 3-hour rolling average period. [District Rules 2201, 4001 and 4703] Federally Enforceable Through Title V Permit

24. Emissions from the gas turbine system, on days when a startup and/or shutdown occurs, shall not exceed the following limits: NOx (as NO2) - 864.8 lb/day; CO - 5,642.0 lb/day; VOC - 179.8 lb/day; PM10 - 240.0 lb/day; SOx (as SO2) - 136.4 lb/day, or NH3 - 641.8 lb/day. [District Rule 2201] Federally Enforceable Through Title V Permit

25. Emissions from the gas turbine system, on days when a startup and/or shutdown does not occur, shall not exceed the following: NOX (as NO2) - 346.6 lb/day; CO - 316.8 lb/day; VOC - 103.8 lb/day; PM10 - 240.0 lb/day; SOX (as SO2) - 136.4 lb/day, or NH3 - 641.8 lb/day. [District Rule 2201] Federally Enforceable Through Title V Permit

26. NH3 emissions shall not exceed any of the following limits: 10.0 ppmvd @ 15% O2 over a 24-hour rolling average period, 25.25 lb/hr while gas turbine system operates with no duct burner firing and 28.23 lb/hr while gas turbine system operates with duct burner firing. [District Rule 2201] Federally Enforceable Through Title V Permit

27. Gas turbine system shall be fired on PUC-regulated natural gas with a sulfur content of no greater than 1.0 grain of sulfur compounds (as S) per 100 dscf of natural gas. [District Rule 2201 and 40 CFR 60.4330(a)(2)] Federally Enforceable Through Title V Permit

28. Each 3-hour rolling average period will be complied from the three most recent one hour periods. Each one hour period shall commence on the hour. Each one hour period in a twenty-four hour average for ammonia slip will commence on the hour. The twenty-four hour average will be calculated starting and ending at twelve-midnight. [District Rule 2201] Federally Enforceable Through Title V Permit

29. Daily emissions will be compiled for a twenty-four hour period starting and ending at twelve-midnight. [District Rule 2201] Federally Enforceable Through Title V Permit

30. NOx (as NO2) emissions from the gas turbine system shall not exceed any of the following: 1st quarter: 35,688 lb; 2nd quarter: 36,015 lb; 3rd quarter: 35,287 lb; 4th quarter: 35,661 lb. [District Rule 2201] Federally Enforceable Through Title V Permit

31. CO emissions from the gas turbine system shall not exceed any of the following: 1st quarter: 147,429 lb; 2nd quarter: 147,728 lb; 3rd quarter: 93,691 lb; 4th quarter: 119,909 lb. [District Rule 2201] Federally Enforceable Through Title V Permit

32. VOC emissions from the gas turbine system shall not exceed any of the following: 1st quarter: 8,077 lb; 2nd quarter: 8,157 lb; 3rd quarter: 9,732 lb; 4th quarter: 8,915 lb. [District Rule 2201] Federally Enforceable Through Title V Permit

33. NH3 emissions from the SCR system shall not exceed any of the following: 1st quarter: 55,584 lb; 2nd quarter: 56,190 lb; 3rd quarter: 59,030 lb; 4th quarter: 57,838 lb. [District Rule] Federally Enforceable Through Title V Permit

34. PM10 emissions from the gas turbine system shall not exceed any of the following: 1st quarter: 20,140 lb; 2nd quarter: 20,356 lb; 3rd quarter: 22,072 lb; 4th quarter: 21,272 lb. [District Rule 2201] Federally Enforceable Through Title V Permit

35. SOx (as SO2) emissions from the gas turbine system shall not exceed any of the following: 1st quarter: 11,820 lb; 2nd quarter: 11,949 lb; 3rd quarter: 12,550 lb; 4th quarter: 12,298 lb. [District Rule 2201] Federally Enforceable Through Title V Permit

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CONDITIONS CONTINUE ON NEXT PAGE

36. A selective catalytic reduction (SCR) system and an oxidation catalyst shall serve the gas turbine system. [District Rule 2201] Federally Enforceable Through Title V Permit

37. The gas turbine engine and generator lube oil vents shall be equipped with mist eliminators or equivalent technology sufficient to limit the visible emissions from the lube oil vents to not exceed 5% opacity, except for a period not exceeding three minutes in any one hour. [District Rule 2201] Federally Enforceable Through Title V Permit

38. Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081] Federally Enforceable Through Title V Permit

39. Source testing shall be witnessed or authorized by District personnel and samples shall be collected by a California Air Resources Board (CARB) certified testing laboratory or a CARB certified source testing firm. [District Rule 1081] Federally Enforceable Through Title V Permit

40. Source testing to measure start-up emission rates of NOx, CO and VOC shall be conducted before the end of commissioning period and at least once every seven years thereafter. CEMS relative accuracy shall be determined during source testing in accordance with the procedure listed in 40 CFR Part 60, Appendix B. [District Rule 1081] Federally Enforceable Through Title V Permit

41. Source testing to determine compliance with the NOx, CO, VOC, and NH3 emission rates (lb/hr and ppmvd @ 15% O2) and PM10 emission rate (lb/hr) shall be conducted within 60 days after the end of commissioning period and at least once every 12 months thereafter. [District Rules 2201 and 4703, 40 CFR 60.4400(a)] Federally Enforceable Through Title V Permit

42. Compliance with the NOx and CO emission limits shall be demonstrated with the duct burner both on and off configurations. [District Rule 4703, 6.3.3] Federally Enforceable Through Title V Permit

43. The sulfur content of each fuel source shall be: (i) documented in a valid purchase contract, a supplier certification, a tariff sheet or transportation contract, or (ii) monitored within 60 days after the end of commissioning period and weekly thereafter. If the sulfur content is less than or equal to 1.0 gr/100 dscf for eight consecutive weeks, then the monitoring frequency shall be every six months. If the result of any six month monitoring demonstrates that the fuel does not meet the fuel sulfur content limit, weekly monitoring shall resume until compliance is demonstrated for eight consecutive weeks. [District Rule 2201 and 40 CFR 60.4360, 60.4365(a) and 60.4370(c)] Federally Enforceable Through Title V Permit

44. The following test methods shall be used: NOx - EPA Method 7E or 20 or CARB Method 100; CO - EPA Method 10 or 10B or CARB Method 100; VOC - EPA Method 18 or 25; PM10 - EPA Method 5 (front half and back half) or 201 and 202a; ammonia - BAAQMD ST-1B; and O2 - EPA Method 3, 3A, or 20 or CARB Method 100. EPA approved alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4703, 40 CFR 60.4400(1)(i)] Federally Enforceable Through Title V Permit

45. Fuel sulfur content shall be monitored using one of the following methods: ASTM Methods D1072, D3246, D4084, D4468, D4810, D6228, D6667 or Gas Processors Association Standard 2377. [40 CFR 60.4415(a)(1)(i)] Federally Enforceable Through Title V Permit

46. The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081] Federally Enforceable Through Title V Permit

47. A non-resettable, totalizing mass or volumetric fuel flow meter to measure the amount of natural gas combusted in the unit shall be installed, utilized and maintained. [District Rules 2201 and 4703] Federally Enforceable Through Title V Permit

48. The owner or operator shall install, certify, maintain, operate, and quality-assure a continuous emission monitor system (CEMS) which continuously measures and records the exhaust gas NOx, CO, and O2 concentrations. Continuous emissions monitors shall be capable of monitoring emissions during normal operating conditions and during startups and shutdowns, provided that CEMS passes the relative accuracy requirement listed in 40 CFR Part 60, Appendix B, Performance Specification 2 (PS-2). If relative accuracy of CEMS cannot be demonstrated during the startup, CEMS results during startup and shutdown events shall be replaced with startup emission rates obtained from the source test to determine compliance with emission limits contained in this document. [District Rules 1080, 2201 and 4703, 40 CFR 60.4340(b)(1) and 40 CFR 60.4345(a)] Federally Enforceable Through Title V Permit

CONDITIONS CONTINUE ON NEXT PAGE

49. NOx, CO and O2 CEMS shall meet the requirements in 40 CFR Part 60, Appendix F Procedure 1 and Part 60, Appendix B Performance Specification 2 (PS 2), or shall meet equivalent specifications established by mutual agreement of the District, the CARB, and the EPA. [District Rule 1080 and 40 CFR 60.4345(a)] Federally Enforceable Through Title V Permit

50. The CEMS shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour or shall meet equivalent specifications established by mutual agreement of the District, the CARB and the EPA. [District Rule 1080 and 40 CFR 60.4345(b)] Federally Enforceable Through Title V Permit

51. The CEMS data shall be reduced to hourly averages as specified in §60.13(h) and in accordance with §60.4350, or by other methods deemed equivalent by mutual agreement with the District, the CARB, and the EPA. [District Rule 1080 and 40 CFR 60.4350] Federally Enforceable Through Title V Permit

52. In accordance with 40 CFR Part 60, Appendix F, 5.1, each CEMS must be audited at least once each calendar quarter. CEMS audit is not required for the quarters in which both relative accuracy test audit (RATA) and source testing are performed. The District shall be notified prior to completion of the audits. Audit reports shall be submitted along with quarterly compliance reports to the District. [District Rule 1080] Federally Enforceable Through Title V Permit

53. The owner or operator shall perform RATA for NOx, CO and O2 as specified by 40 CFR Part 60, Appendix F, 5.1.1, at least once every four calendar quarters. The permittee shall comply with the applicable requirements for quality assurance testing and maintenance of the continuous emission monitor equipment in accordance with the procedures and guidance specified in 40 CFR Part 60, Appendix F. [District Rule 1080] Federally Enforceable Through Title V Permit

54. Upon written notice from the District, the owner or operator shall provide a summary of the data obtained from the CEMS. This summary shall be in the form and the manner prescribed by the District. [District Rule 1080] Federally Enforceable Through Title V Permit

55. The facility shall install and maintain equipment, facilities, and systems compatible with the District's CEMS data polling software system and shall make CEMS data available to the District's automated polling system on a daily basis. Upon notice by the District that the facility's CEMS is not providing polling data, the facility may continue to operate without providing automated data for a maximum of 30 days per calendar year provided the CEMS data is sent to the District by a District-approved alternative method. [District Rule 1080] Federally Enforceable Through Title V Permit

56. The owner or operator shall maintain the following records: the date, time and duration of any malfunction of the continuous monitoring equipment; dates of performance testing; dates of evaluations, calibrations, checks, and adjustments of the continuous monitoring equipment; date and time period which a continuous monitoring system or monitoring device was inoperative. [District Rules 1080 and 2201 and 40 CFR 60.8(d)] Federally Enforceable Through Title V Permit

57. The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, CO, and O2 analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Emission Monitoring and Testing. [District Rule 1081] Federally Enforceable Through Title V Permit

58. Monitor Downtime is defined as any unit operating hour in which the data for NOx, CO2 or O2 concentrations is either missing or invalid. [40 CFR 60.4380(b)(2)] Federally Enforceable Through Title V Permit

59. The owner or operator shall maintain records of the following items: 1) hourly and daily emissions, in pounds, for each pollutant listed in this permit on the days startup and or shutdown of the gas turbine system occurs, 2) hourly and daily emissions, in pounds, for each pollutant in this permit on the days startup and or shutdown of the gas turbine system does not occur, 3) quarterly emissions, in pounds, for each pollutant listed in this permit. [District Rule 2201] Federally Enforceable Through Title V Permit

60. The owner or operator shall maintain a stationary gas turbine system operating log that includes, on a daily basis, the actual local startup and stop time, length and reason for reduced load periods, total hours of operation, the type and quantity of fuel used, duration of start-up, duration of shutdown, date/time and duration of each primary re-ignition period. [District Rule 2201 and 4703, 6.26, 6.28, 6.2.11] Federally Enforceable Through Title V Permit

CONDITIONS CONTINUE ON NEXT PAGE

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61. The owner or operator shall maintain all records of required monitoring data and support information for a period of five years from the date of data entry and shall make such records available to the District upon request. [District Rules 2201 and 4703, 6.2.4] Federally Enforceable Through Title V Permit

62. The owner or operator shall submit a written report of CEM operations for each calendar quarter to the District. The report is due on the 30th day following the end of the calendar quarter and shall include the following: Time intervals, data and magnitude of excess NOx emissions, nature and the cause of excess (if known), corrective actions taken and preventive measures adopted; Averaging period used for data reporting corresponding to the averaging period specified in the emission test period used to determine compliance with an emission standard; Applicable time and date of each period during which the CEM was inoperative, except for zero and span checks, and the nature of system repairs and adjustments; A negative declaration when no excess emissions occurred. [District Rule 1080 and 40 CFR 60.4375(a) and 60.4395] Federally Enforceable Through Title V Permit

63. The primary re-ignition period shall be defined as the duration of time during which a gas turbine is operated at less than rated capacity in order to reset the dry low-NOx combustion system following a primary re-ignition provided that all of the following are met: 1) the duration of a primary re-ignition period shall not exceed one hour; 2) NOx emissions shall not exceed 15 ppmvd, corrected to 15% O2, averaged over one hour; and 3) CO emissions shall not exceed 25 ppmvd, corrected to 15% O2. [District Rule 4703, 5.3.1.3, 3.20] Federally Enforceable Through Title V Permit

64. Reduced load period is defined as the time during which a gas turbine is operated at less than rated capacity in order to change the position of the exhaust gas diverter gate. Each reduced load period shall not exceed one hour. [District Rule 4703, 5.3.1.4 and 3.23] Federally Enforceable Through Title V Permit

65. The owner or operator shall submit to the District information correlating the NOx control system operating parameters to the associated measured NOx output. The information must be sufficient to allow the District to determine compliance with the NOx emission limits of this permit when the CEMS is not operating properly. [District Rule 4703, 6.2.5] Federally Enforceable Through Title V Permit

66. Disturbances of soil related to any construction, demolition, excavation, extraction, or other earthmoving activities shall comply with the requirements for fugitive dust control in District Rule 8021 unless specifically exempted under Section 4.0 of Rule 8021 or Rule 8011. [District Rules 8011 and 8021] Federally Enforceable Through Title V Permit

67. An owner/operator shall submit a Dust Control Plan to the APCO prior to the start of any construction activity on any site that will include 10 acres or more of disturbed surface area for residential developments, or 5 acres or more of disturbed surface area for non-residential development, or will include moving, depositing, or relocating more than 2,500 cubic yards per day of bulk materials on at least three days. [District Rules 8011 and 8021] Federally Enforceable Through Title V Permit

68. An owner/operator shall prevent or cleanup any carryout or trackout in accordance with the requirements of District Rule 8041 Section 5.0, unless specifically exempted under Section 4.0 of Rule 8041 or Rule 8011. [District Rules 8011 and 8021] Federally Enforceable Through Title V Permit

69. Whenever open areas are disturbed, or vehicles are used in open areas, the facility shall comply with the requirements of Section 5.0 of District Rule 8051, unless specifically exempted under Section 4.0 of Rule 8051 or Rule 8011. [District Rules 8011 and 8051] Federally Enforceable Through Title V Permit

70. Any paved road or unpaved road shall comply with the requirements of District Rule 8061 unless specifically exempted under Section 4.0 of Rule 8061 or Rule 8011. [District Rules 8011 and 8061] Federally Enforceable Through Title V Permit

71. Water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure shall be applied to unpaved vehicle travel areas as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071] Federally Enforceable Through Title V Permit

72. Where dusting materials are allowed to accumulate on paved surfaces, the accumulation shall be removed daily or water and/or chemical/organic dust stabilizers/suppressants shall be applied to the paved surface as required to maintain continuous compliance with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011 and limit Visible Dust Emissions (VDE) to 20% opacity. [District Rule 8011 and 8071] Federally Enforceable Through Title V Permit

CONDITIONS CONTINUE ON NEXT PAGE

73. On each day that 50 or more Vehicle Daily Trips or 25 or more Vehicle Daily Trips with 3 axles or more will occur on an unpaved vehicle/equipment traffic area, permittee shall apply water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071] Federally Enforceable Through Title V Permit

74. Whenever any portion of the site becomes inactive, Permittee shall restrict access and periodically stabilize any disturbed surface to comply with the conditions for a stabilized surface as defined in Section 3.58 of District Rule 8011. [District Rules 8011 and 8071] Federally Enforceable Through Title V Permit

75. Records and other supporting documentation shall be maintained as required to demonstrate compliance with the requirements of the rules under Regulation VIII only for those days that a control measure was implemented. Such records shall include the type of control measure(s) used, the location and extent of coverage, and the date, amount, and frequency of application of dust suppressant, manufacturer's dust suppressant product information sheet that identifies the name of the dust suppressant and application instructions. Records shall be kept for one year following project completion that results in the termination of all dust generating activities. [District Rules 8011, 8031 and 8071] Federally Enforceable Through Title V Permit

76. Prior to operating under ATCs N-2697-5-0 and N-2697-7-0, the permittee shall mitigate the following quantities of NOx: 1st quarter: 35,766 lb, 2nd quarter: 36,093 lb, 3rd quarter: 35,329 lb, and 4th quarter: 35,721 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 9/21/06). [District Rule 2201] Federally Enforceable Through Title V Permit

77. NOx ERCs S-2857-2, S-2848-2, S-2849-2, S-2850-2, S-2851-2, S-2852-2, S-2854-2, S-2855-2, C-915-2, C-916-2, C-914-2, N-755-2, N-754-2, S-2894-2 and S-2895-2 (or a certificate split from any of these certificates) shall be used to supply the required NOx offsets, unless a revised offsetting proposal is received and approved by the District. Following the revisions, this Authority to Construct permit shall be re-issued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to re-issuance of this Authority to Construct permit. [District Rule 2201] Federally Enforceable Through Title V Permit

78. Prior to operating under ATCs N-2697-5-0 and N-2697-7-0, the permittee shall mitigate the following quantities of VOC: 1st quarter: 8,116 lb, 2nd quarter: 8,196 lb, 3rd quarter: 9,753 lb, and 4th quarter: 8,945 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 9/21/06). [District Rule 2201] Federally Enforceable Through Title V Permit

79. VOC ERC S-2860-1, and NOx ERCs S-2857-2, S-2848-2, S-2849-2, S-2850-2, S-2851-2, S-2852-2, S-2854-2, S-2855-2, C-915-2, C-916-2, C-914-2, N-755-2, N-754-2, S-2894-2 and S-2895-2 (or a certificate split from any of these certificates) shall be used to supply the required VOC offsets, unless a revised offsetting proposal is received and approved by the District. Following the revisions, this Authority to Construct permit shall be re-issued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to re-issuance of this Authority to Construct permit. [District Rule 2201] Federally Enforceable Through Title V Permit

80. The District has authorized to use NOx reductions to overcome shortfall in the amount of VOC offsets at NOx/VOC interpollutant offset ratio of 1.00. [District Rule 2201] Federally Enforceable Through Title V Permit

81. Prior to operating under ATCs N-2697-5-0 and N-2697-7-0, the permittee shall mitigate the following quantities of SOx: 1st quarter: 1,326 lb, 2nd quarter: 1,381 lb, 3rd quarter: 1,436 lb, and 4th quarter: 1,381 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 9/21/06). [District Rule 2201] Federally Enforceable Through Title V Permit

82. SOx ERCs S-2843-5, S-2845-5, S-2858-5, N-759-5, N-758-5, S-2846-5 and N-757-5 (or a certificate split from any of these certificates) shall be used to supply the required SOx offsets, unless a revised offsetting proposal is received and approved by the District. Following the revisions, this Authority to Construct permit shall be re-issued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to re-issuance of this Authority to Construct permit. [District Rule 2201] Federally Enforceable Through Title V Permit

CONDITIONS CONTINUE ON NEXT PAGE

83. Prior to operating under ATCs N-2697-5-0, N-2697-6-0 and N-2697-7-0, the permittee shall mitigate the following quantities of PM10: 1st quarter: 18,321 lb, 2nd quarter: 18,321 lb, 3rd quarter: 20,611 lb, and 4th quarter: 19,084 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 9/21/06). [District Rule 2201] Federally Enforceable Through Title V Permit

84. PM10 ERCs S-2844-4, C-911-4, N-756-4, C-913-4, C-912-4, and SOx ERCs S-2843-5, S-2845-5, S-2858-5, N-759-5, N-758-5, S-2846-5 and N-757-5 (or a certificate split from any of these certificates) shall be used to supply the required PM10 offsets, unless a revised offsetting proposal is received and approved by the District. Following the revisions, this Authority to Construct permit shall be re-issued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to re-issuance of this Authority to Construct permit. [District Rule 2201] Federally Enforceable Through Title V Permit

85. The District has authorized to use SOx reductions to overcome shortfall in the amount of PM10 offsets at SOx/PM10 interpollutant offset ratio of 1.00. [District Rule 2201] Federally Enforceable Through Title V Permit

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San Joaquin Valley
Air Pollution Control District

AUTHORITY TO CONSTRUCT

DRAFT

PERMIT NO: N-2697-6-0 **ISSUANCE DATE:** DRAFT

LEGAL OWNER OR OPERATOR: NORTHERN CALIFORNIA POWER
MAILING ADDRESS: 651 COMMERCE DR
ROSEVILLE, CA 95678

LOCATION: 12751 N THORNTON RD
LODI, CA 95241

EQUIPMENT DESCRIPTION:
60,000 GALLON/MIN COOLING TOWER WITH SEVEN CELLS SERVED BY HIGH EFFICIENCY DRIFT ELIMINATORS

CONDITIONS

1. The permittee shall not begin actual onsite construction of the equipment authorized by this Authority to Construct until the lead agency satisfies the requirements of the California Environmental Quality Act (CEQA). [California Environmental Quality Act]
2. {1830} This Authority to Construct serves as a written certificate of conformity with the procedural requirements of 40 CFR 70.7 and 70.8 and with the compliance requirements of 40 CFR 70.6(c). [District NSR Rule] Federally Enforceable Through Title V Permit
3. {1831} Prior to operating with modifications authorized by this Authority to Construct, the facility shall submit an application to modify the Title V permit with an administrative amendment in accordance with District Rule 2520 Section 5.3.4. [District Rule 2520, 5.3.4] Federally Enforceable Through Title V Permit
4. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
5. The owner or operator shall notify the District of any breakdown condition as soon as reasonably possible, but no later than one hour after its detection, unless the owner or operator demonstrates to the District's satisfaction that the longer reporting period was necessary. [District Rule 1100]
6. The District shall be notified in writing within ten days following the correction of any breakdown condition. The breakdown notification shall include a description of the equipment malfunction or failure, the date and cause of the initial failure, the estimated emissions in excess of those allowed, and the methods utilized to restore normal operations. [District Rule 1100]

CONDITIONS CONTINUE ON NEXT PAGE

YOU MUST NOTIFY THE DISTRICT COMPLIANCE DIVISION AT (209) 557-6400 WHEN CONSTRUCTION IS COMPLETED AND PRIOR TO OPERATING THE EQUIPMENT OR MODIFICATIONS AUTHORIZED BY THIS AUTHORITY TO CONSTRUCT. This is NOT a PERMIT TO OPERATE. Approval or denial of a PERMIT TO OPERATE will be made after an inspection to verify that the equipment has been constructed in accordance with the approved plans, specifications and conditions of this Authority to Construct, and to determine if the equipment can be operated in compliance with all Rules and Regulations of the San Joaquin Valley Unified Air Pollution Control District. Unless construction has commenced pursuant to Rule 2050, this Authority to Construct shall expire and application shall be cancelled two years from the date of issuance. The applicant is responsible for complying with all laws, ordinances and regulations of all other governmental agencies which may pertain to the above equipment.

Seyed Sadredin, Executive Director / APCO

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DAVID WARNER, Director of Permit Services
N-2697-6-0 : Apr 13 2009 12:02PM – KAHLONJ . Joint Inspection Required with KAHLONJ

7. No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101] Federally Enforceable Through Title V Permit
8. Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201] Federally Enforceable Through Title V Permit
9. No hexavalent chromium containing compounds shall be added to cooling tower circulating water. [District Rule 7012] Federally Enforceable Through Title V Permit
10. The drift rate shall not exceed 0.0005%. [District Rule 2201] Federally Enforceable Through Title V Permit
11. PM10 emissions shall not exceed 10.8 pounds per day. [District Rule 2201] Federally Enforceable Through Title V Permit
12. Compliance with the PM10 emission limit (lb/day) shall be demonstrated by using the following equation: Water Recirculation Rate (gal/day) x 8.34 lb/gal x Total Dissolved Solids Concentration in the blowdown water (ppm x 10E-06) x Design Drift Rate (%). [District Rule 2201] Federally Enforceable Through Title V Permit
13. Compliance with PM10 emission limit shall be determined by blowdown water sample analysis by independent laboratory within 60 days after the end of commissioning period of the gas turbine system and at least once quarterly thereafter. [District Rules 2201 and 1081] Federally Enforceable Through Title V Permit
14. Prior to operating under ATCs N-2697-5-0, N-2697-6-0 and N-2697-7-0, the permittee shall mitigate the following quantities of PM10: 1st quarter: 18,321 lb, 2nd quarter: 18,321 lb, 3rd quarter: 20,611 lb, and 4th quarter: 19,084 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 9/21/06). [District Rule 2201] Federally Enforceable Through Title V Permit
15. PM10 ERCs S-2844-4, C-911-4, N-756-4, C-913-4, C-912-4, and SOx ERCs S-2843-5, S-2845-5, S-2858-5, N-759-5, N-758-5, S-2846-5 and N-757-5 (or a certificate split from any of these certificates) shall be used to supply the required PM10 offsets, unless a revised offsetting proposal is received and approved by the District. Following the revisions, this Authority to Construct permit shall be re-issued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to re-issuance of this Authority to Construct permit. [District Rule 2201] Federally Enforceable Through Title V Permit
16. The District has authorized to use SOx reductions to overcome shortfall in the amount of PM10 offsets at SOx/PM10 interpollutant offset ratio of 1.00. [District Rule 2201] Federally Enforceable Through Title V Permit

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San Joaquin Valley
Air Pollution Control District

AUTHORITY TO CONSTRUCT

PERMIT NO: N-2697-7-0 **ISSUANCE DATE:** DRAFT

LEGAL OWNER OR OPERATOR: NORTHERN CALIFORNIA POWER
MAILING ADDRESS: 651 COMMERCE DR
ROSEVILLE, CA 95678

LOCATION: 12751 N THORNTON RD
LODI, CA 95241

EQUIPMENT DESCRIPTION:
65 MMBTU/HR RENTECH BOILER SYSTEMS INC "D" TYPE BOILER EQUIPPED WITH A TODD/COEN RMB ULTRA LOW-NOX BURNER (PART OF GE'S "RAPID RESPONSE" SYSTEM)

CONDITIONS

1. The permittee shall not begin actual onsite construction of the equipment authorized by this Authority to Construct until the lead agency satisfies the requirements of the California Environmental Quality Act (CEQA). [California Environmental Quality Act]

2. {1830} This Authority to Construct serves as a written certificate of conformity with the procedural requirements of 40 CFR 70.7 and 70.8 and with the compliance requirements of 40 CFR 70.6(c). [District NSR Rule] Federally Enforceable Through Title V Permit

3. {1831} Prior to operating with modifications authorized by this Authority to Construct, the facility shall submit an application to modify the Title V permit with an administrative amendment in accordance with District Rule 2520 Section 5.3.4. [District Rule 2520, 5.3.4] Federally Enforceable Through Title V Permit

4. All equipment shall be maintained in good operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District Rule 2201] Federally Enforceable Through Title V Permit

5. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

6. No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101] Federally Enforceable Through Title V Permit

CONDITIONS CONTINUE ON NEXT PAGE

YOU MUST NOTIFY THE DISTRICT COMPLIANCE DIVISION AT (209) 557-6400 WHEN CONSTRUCTION IS COMPLETED AND PRIOR TO OPERATING THE EQUIPMENT OR MODIFICATIONS AUTHORIZED BY THIS AUTHORITY TO CONSTRUCT. This is NOT a PERMIT TO OPERATE. Approval or denial of a PERMIT TO OPERATE will be made after an inspection to verify that the equipment has been constructed in accordance with the approved plans, specifications and conditions of this Authority to Construct, and to determine if the equipment can be operated in compliance with all Rules and Regulations of the San Joaquin Valley Unified Air Pollution Control District. Unless construction has commenced pursuant to Rule 2050, this Authority to Construct shall expire and application shall be cancelled two years from the date of issuance. The applicant is responsible for complying with all laws, ordinances and regulations of all other governmental agencies which may pertain to the above equipment.

Seyed Sadredin, Executive Director / APCO

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DAVID WARNER, Director of Permit Services

N-2697-7-0 : Apr 13 2009 12:02PM – KAHLONJ · Joint Inspection Required with KAHLONJ

7. Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201] Federally Enforceable Through Title V Permit
8. The unit shall only be fired on PUC-regulated natural gas. [District Rules 2201 and 4320] Federally Enforceable Through Title V Permit
9. A non-resettable, totalizing mass or volumetric fuel flow meter to measure the amount of natural gas combusted in the unit shall be installed, utilized and maintained. [District Rule 2201, 40 CFR60.48(c)(g)] Federally Enforceable Through Title V Permit
10. The total mass emissions of NOx, VOC, CO, PM10 and SOx that are emitted during the commissioning period shall accrue towards the quarterly emission limits. [District Rule 2201] Federally Enforceable Through Title V Permit
11. During commissioning period, the owner or operator shall keep records of the natural gas fuel combusted in the boiler on daily basis. [District Rule 2201]
12. The owner or operator shall notify the District of any breakdown condition as soon as reasonably possible, but no later than one hour after its detection, unless the owner or operator demonstrates to the District's satisfaction that the longer reporting period was necessary. [District Rule 1100]
13. The District shall be notified in writing within ten days following the correction of any breakdown condition. The breakdown notification shall include a description of the equipment malfunction or failure, the date and cause of the initial failure, the estimated emissions in excess of those allowed, and the methods utilized to restore normal operations. [District Rule 1100]
14. NOx (as NO2) emissions shall not exceed 7.0 ppmvd @ 3% O2. [District Rules 2201, 4305, 4306 and 4320] Federally Enforceable Through Title V Permit
15. CO emissions shall not exceed 50 ppmvd @ 3% O2. [District Rules 2201, 4305, 4306 and 4320] Federally Enforceable Through Title V Permit
16. VOC (as CH4) emissions shall not exceed 10.0 ppmvd @ 3% O2. [District Rule 2201] Federally Enforceable Through Title V Permit
17. PM10 emissions shall not exceed 0.0076 lb/MMBtu. [District Rule 2201] Federally Enforceable Through Title V Permit
18. SOx emissions shall not exceed 0.00285 lb/MMBtu. [District Rule 2201] Federally Enforceable Through Title V Permit
19. Heat input rate to this unit shall not exceed 780 MMBtu/day. [District Rule 2201] Federally Enforceable Through Title V Permit
20. NOx (as NO2) emissions from this unit shall not exceed any of the following: 1st quarter: 78 lb; 2nd quarter: 78 lb; 3rd quarter: 42 lb; 4th quarter: 60 lb. [District Rule 2201] Federally Enforceable Through Title V Permit
21. CO emissions from this unit shall not exceed any of the following: 1st quarter: 341 lb; 2nd quarter: 341 lb; 3rd quarter: 182 lb; 4th quarter: 259 lb. [District Rule 2201] Federally Enforceable Through Title V Permit
22. VOC emissions from this unit shall not exceed any of the following: 1st quarter: 39 lb; 2nd quarter: 39 lb; 3rd quarter: 21 lb; 4th quarter: 30 lb. [District Rule 2201] Federally Enforceable Through Title V Permit
23. PM10 emissions from this unit shall not exceed any of the following: 1st quarter: 70 lb; 2nd quarter: 70 lb; 3rd quarter: 38 lb; 4th quarter: 53 lb. [District Rule 2201] Federally Enforceable Through Title V Permit
24. SOx (as SO2) emissions from this unit shall not exceed any of the following: 1st quarter: 26 lb; 2nd quarter: 26 lb; 3rd quarter: 14 lb; 4th quarter: 20 lb. [District Rule 2201] Federally Enforceable Through Title V Permit
25. All emissions measurements shall be made with the unit operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. No determination of compliance shall be established within two hours after a continuous period in which fuel flow to the unit is shut off for 30 minutes or longer, or within 30 minutes after a re-ignition as defined in Section 3.0 of District Rule 4306. [District Rules 4305 and 4306] Federally Enforceable Through Title V Permit

CONDITIONS CONTINUE ON NEXT PAGE

26. Source testing to measure NOx and CO emissions from this unit while fired on natural gas shall be conducted within 60 days of the end of commissioning period of the gas turbine system. [District Rules 2201, 4305 and 4306] Federally Enforceable Through Title V Permit

27. Source testing to measure NOx and CO emissions from this unit while fired on natural gas shall be conducted at least once every twelve (12) months. After demonstrating compliance on two (2) consecutive annual source tests, the unit shall be tested not less than once every thirty-six (36) months. If the result of the 36-month source test demonstrates that the unit does not meet the applicable emission limits, the source testing frequency shall revert to at least once every twelve (12) months. [District Rules 4305, 4306 and 4320] Federally Enforceable Through Title V Permit

28. The source test plan shall identify which basis (ppmv or lb/MMBtu) will be used to demonstrate compliance. [District Rules 4305 and 4306] Federally Enforceable Through Title V Permit

29. Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081] Federally Enforceable Through Title V Permit

30. NOx emissions for source test purposes shall be determined using EPA Method 7E or CARB Method 100 on a ppmv basis, or EPA Method 19 on a heat input basis. [District Rules 4305, 4306 and 4320] Federally Enforceable Through Title V Permit

31. CO emissions for source test purposes shall be determined using EPA Method 10 or CARB Method 100. [District Rules 4305, 4306 and 4320] Federally Enforceable Through Title V Permit

32. Stack gas oxygen (O2) shall be determined using EPA Method 3 or 3A or CARB Method 100. [District Rules 4305, 4306 and 4320] Federally Enforceable Through Title V Permit

33. For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit the test cannot be used to demonstrate compliance with an applicable limit. [District Rules 4305, 4306 and 4320] Federally Enforceable Through Title V Permit

34. The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081] Federally Enforceable Through Title V Permit

35. The fuel sulfur content analysis shall be submitted to the District at least once every 12-month period. [District Rule 4320]

36. Fuel sulfur content shall be determined using EPA Method 11 or EPA Method 15 or District, CARB and EPA approved alternative methods. [District Rule 4320]

37. The permittee shall monitor and record the stack concentration of NOx, CO, and O2 at least once every month (in which a source test is not performed) using a portable emission monitor that meets District specifications given in District Policy SSP-1105. Monitoring shall not be required if the unit is not in operation, i.e. the unit need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the unit unless monitoring has been performed within the last month. [District Rules 4305, 4306 and 4320] Federally Enforceable Through Title V Permit

38. If either the NOx or CO concentrations corrected to 3% O2, as measured by the portable analyzer, exceed the allowable emissions concentration, the permittee shall return the emissions to within the acceptable range as soon as possible, but no longer than 1 hour of operation after detection. If the portable analyzer readings continue to exceed the allowable emissions concentration after 1 hour of operation after detection, the permittee shall notify the District within the following 1 hour and conduct a certified source test within 60 days of the first exceedance. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must then correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of the performing the notification and testing required by this condition. [District Rules 4305, 4306 and 4320] Federally Enforceable Through Title V Permit

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CONDITIONS CONTINUE ON NEXT PAGE

39. All alternate monitoring parameter emission readings shall be taken with the unit operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. The analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Emission readings taken shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive-minute sample reading or by taking at least five (5) readings, evenly spaced out over the 15 consecutive-minute period. [District Rules 4305, 4306 and 4320] Federally Enforceable Through Title V Permit

40. The permittee shall maintain records of: (1) the date and time of NOx, CO, and O2 measurements, (2) the O2 concentration in percent and the measured NOx and CO concentrations corrected to 3% O2, (3) make and model of exhaust gas analyzer, (4) exhaust gas analyzer calibration records, and (5) a description of any corrective action taken to maintain the emissions within the acceptable range. [District Rules 4305, 4306 and 4320] Federally Enforceable Through Title V Permit

41. The permittee shall maintain daily records of the type and quantity of fuel combusted by the boiler. [District Rule 2201, 40 CFR 60.48(c)(g)] Federally Enforceable Through Title V Permit

42. The permittee shall maintain records of: (1) the date, (2) heat input rate, MMBtu/day, (3) daily emissions (lb/day) for each pollutant listed in this permit, and (4) quarterly emissions (lb) for each pollutant listed in this permit. [District Rule 2201] Federally Enforceable Through Title V Permit

43. All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rules 1070, 4305, 4306 and 4320] Federally Enforceable Through Title V Permit

44. Prior to operating under ATCs N-2697-5-0 and N-2697-7-0, the permittee shall mitigate the following quantities of NOx: 1st quarter: 35,766 lb, 2nd quarter: 36,093 lb, 3rd quarter: 35,329 lb, and 4th quarter: 35,721 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 9/21/06). [District Rule 2201] Federally Enforceable Through Title V Permit

45. NOx ERCs S-2857-2, S-2848-2, S-2849-2, S-2850-2, S-2851-2, S-2852-2, S-2854-2, S-2855-2, C-915-2, C-916-2, C-914-2, N-755-2, N-754-2, S-2894-2 and S-2895-2 (or a certificate split from any of these certificates) shall be used to supply the required NOx offsets, unless a revised offsetting proposal is received and approved by the District. Following the revisions, this Authority to Construct permit shall be re-issued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to re-issuance of this Authority to Construct permit. [District Rule 2201] Federally Enforceable Through Title V Permit

46. Prior to operating under ATCs N-2697-5-0 and N-2697-7-0, the permittee shall mitigate the following quantities of VOC: 1st quarter: 8,116 lb, 2nd quarter: 8,196 lb, 3rd quarter: 9,753 lb, and 4th quarter: 8,945 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 9/21/06). [District Rule 2201] Federally Enforceable Through Title V Permit

47. VOC ERC S-2860-1, and NOx ERCs S-2857-2, S-2848-2, S-2849-2, S-2850-2, S-2851-2, S-2852-2, S-2854-2, S-2855-2, C-915-2, C-916-2, C-914-2, N-755-2, N-754-2, S-2894-2 and S-2895-2 (or a certificate split from any of these certificates) shall be used to supply the required VOC offsets, unless a revised offsetting proposal is received and approved by the District. Following the revisions, this Authority to Construct permit shall be re-issued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to re-issuance of this Authority to Construct permit. [District Rule 2201] Federally Enforceable Through Title V Permit

48. The District has authorized to use NOx reductions to overcome shortfall in the amount of VOC offsets at NOx/VOC interpollutant offset ratio of 1.00. [District Rule 2201] Federally Enforceable Through Title V Permit

49. Prior to operating under ATCs N-2697-5-0 and N-2697-7-0, the permittee shall mitigate the following quantities of SOx: 1st quarter: 1,326 lb, 2nd quarter: 1,381 lb, 3rd quarter: 1,436 lb, and 4th quarter: 1,381 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 9/21/06). [District Rule 2201] Federally Enforceable Through Title V Permit

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CONDITIONS CONTINUE ON NEXT PAGE

50. SOx ERCs S-2843-5, S-2845-5, S-2858-5, N-759-5, N-758-5, S-2846-5 and N-757-5 (or a certificate split from any of these certificates) shall be used to supply the required SOx offsets, unless a revised offsetting proposal is received and approved by the District. Following the revisions, this Authority to Construct permit shall be re-issued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to re-issuance of this Authority to Construct permit. [District Rule 2201] Federally Enforceable Through Title V Permit

51. Prior to operating under ATCs N-2697-5-0, N-2697-6-0 and N-2697-7-0, the permittee shall mitigate the following quantities of PM10: 1st quarter: 18,321 lb, 2nd quarter: 18,321 lb, 3rd quarter: 20,611 lb, and 4th quarter: 19,084 lb. Offsets shall be provided at the applicable offset ratio specified in Table 4-2 of Rule 2201 (as amended 9/21/06). [District Rule 2201] Federally Enforceable Through Title V Permit

52. PM10 ERCs S-2844-4, C-911-4, N-756-4, C-913-4, C-912-4, and SOx ERCs S-2843-5, S-2845-5, S-2858-5, N-759-5, N-758-5, S-2846-5 and N-757-5 (or a certificate split from any of these certificates) shall be used to supply the required PM10 offsets, unless a revised offsetting proposal is received and approved by the District. Following the revisions, this Authority to Construct permit shall be re-issued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to re-issuance of this Authority to Construct permit. [District Rule 2201] Federally Enforceable Through Title V Permit

53. The District has authorized to use SOx reductions to overcome shortfall in the amount of PM10 offsets at SOx/PM10 interpollutant offset ratio of 1.00. [District Rule 2201] Federally Enforceable Through Title V Permit

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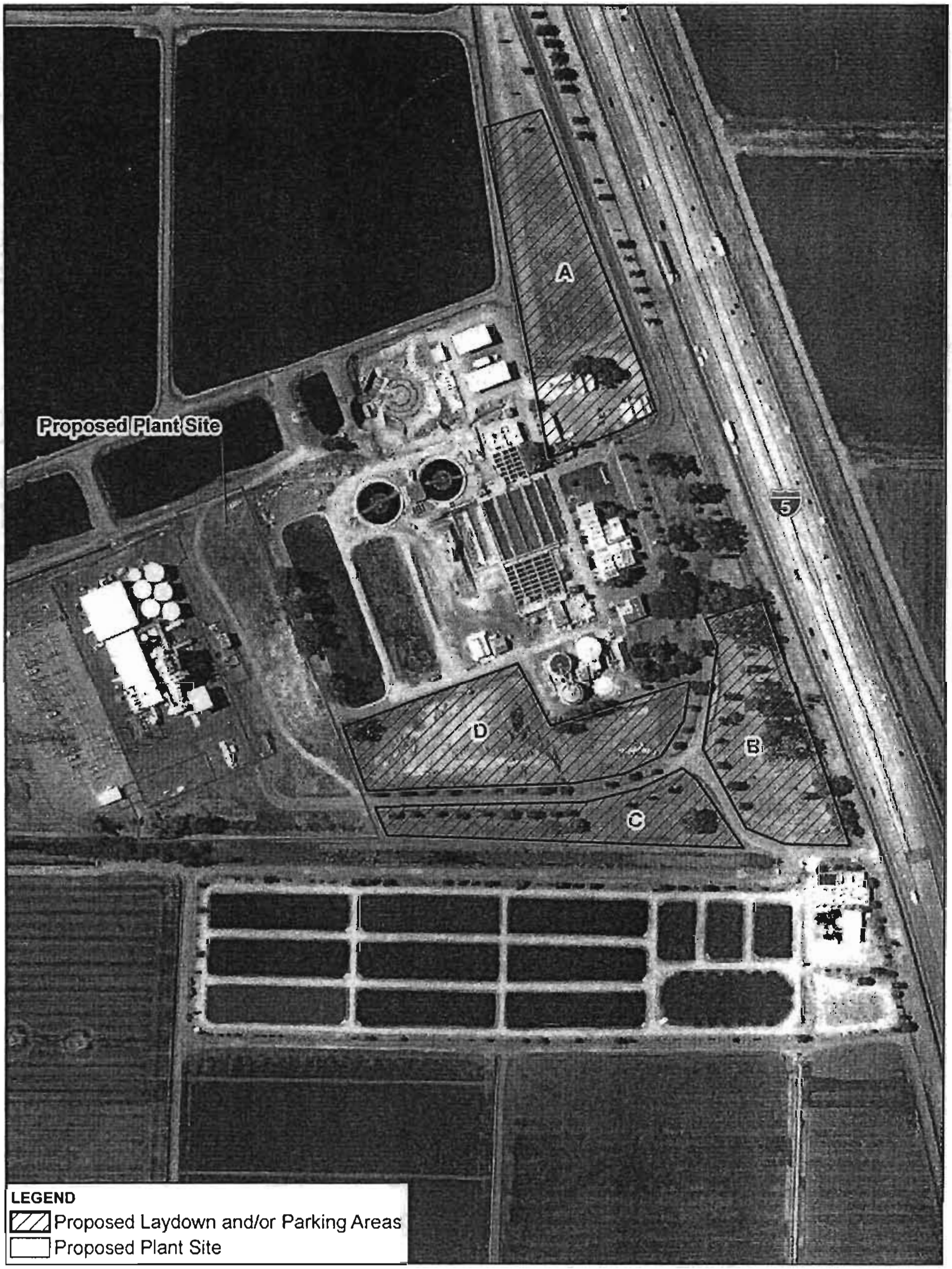
ATTACHMENT B
PROJECT LOCATION AND SITE PLAN



This map was compiled from various scale source data and maps and is intended for use as only an approximate representation of actual locations

0 150 300
Feet

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FIGURE 2.1-3
PROPOSED LAYDOWN AND PARKING AREAS
LODI ENERGY CENTER
LODI, CAIFORNIA

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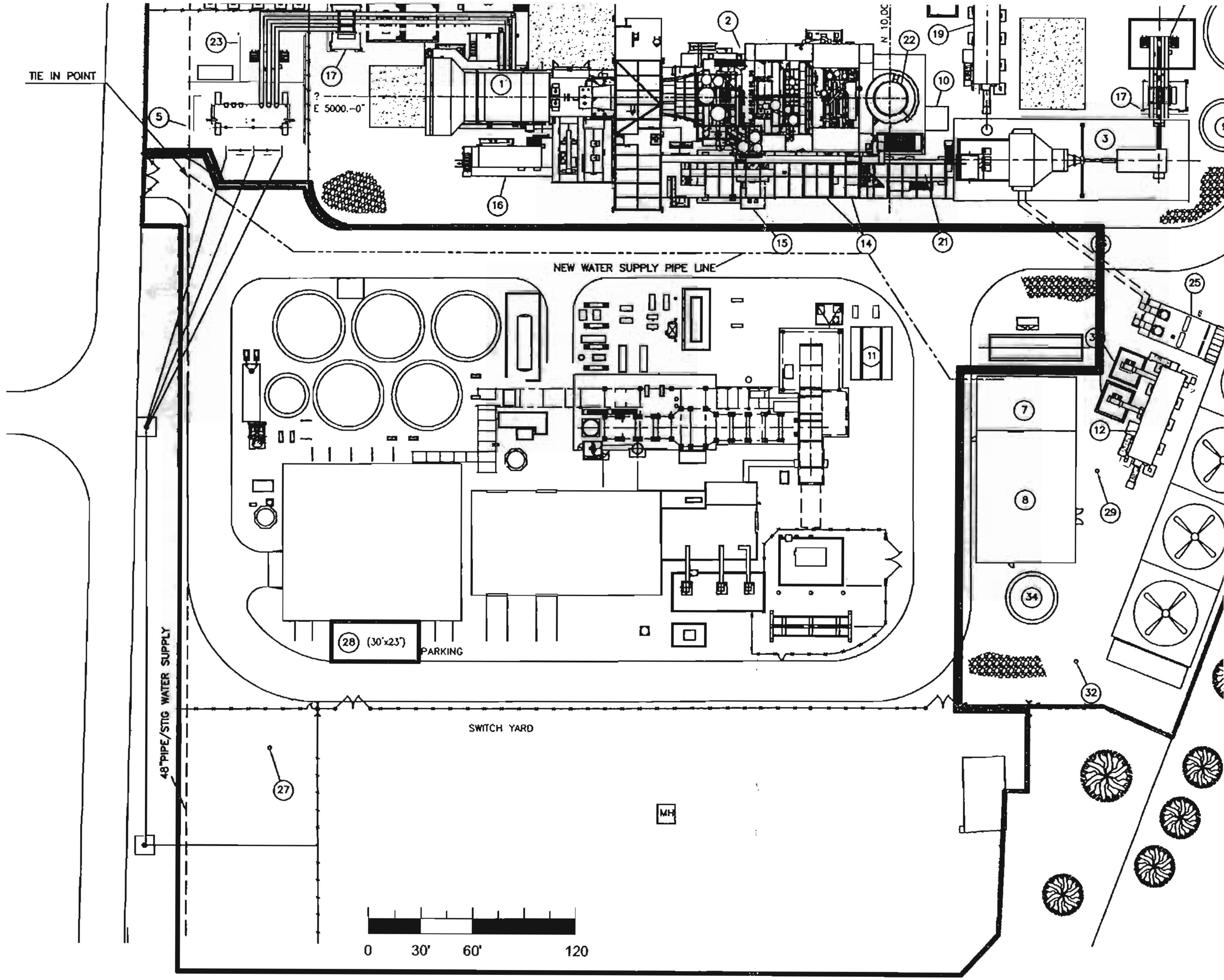

Source: Worley Parsons LTD, Drawing LODI-0-SK-111-007-001C, 08-28-08

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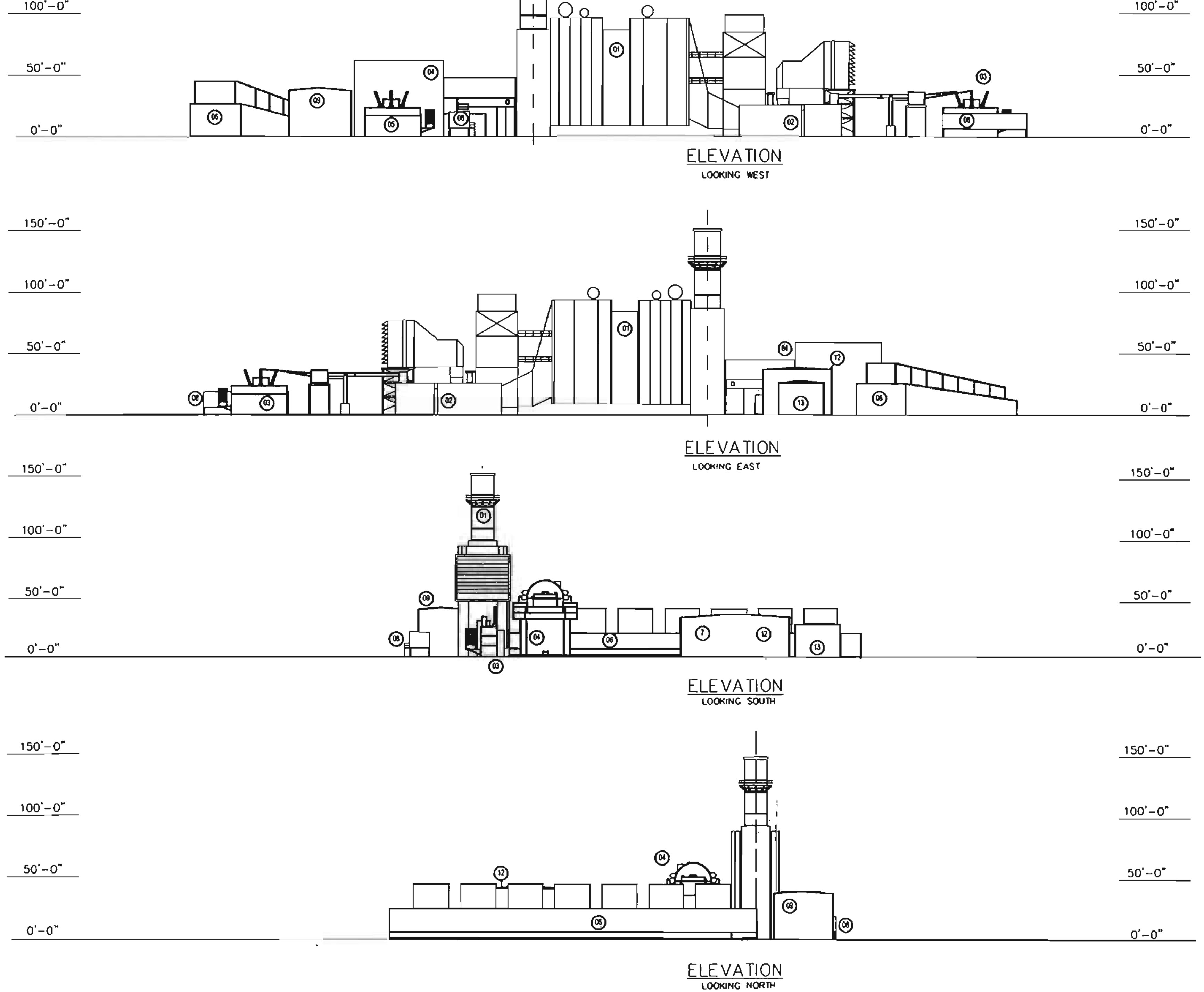

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Source: Worley Parsons LTD, LODI-0-SK-111-002-101A, 08-28-08

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ATTACMENT C
CTG COMMISSIONG PERIOD EMISSIONS DATA

5.1 Air Quality

2. Compliance Determination (Appendix B (g) (8) (A))

The information necessary for the air pollution control district where the project is located to complete a Determination of Compliance.

Information required to make AFC conform with regulations:

Please provide a copy of the District's Notice of Completeness.

Response: A copy of the District's completeness letter dated October 2, 2008, was docketed on October 23, 2008. A copy of the letter is provided as Attachment DA 5.1-1.

3. Emission Quantification (Appendix B(g) (8) (F)(ii)

A description of the project's planned initial commissioning phase, which is the phase between the first firing of emissions sources and the commercial operations date, including the types and durations of equipment tests, criteria pollutant emissions, and monitoring techniques to be used during such tests.

Information required to make AFC conform with regulations:

Please provide description, duration and quantification of emissions for each commissioning activity.

Please provide method(s) to monitor the emissions of each commissioning activity.

Response: Each commissioning activity is described below. The expected duration and quantification of emissions from each commissioning activity are provided in Tables AQ-1 and AQ-2, attached as Attachment DA 5.1--2.

- Full Speed No Load Tests (FSNL) - This activity includes a test of the gas turbine ignition system, a test to assure that the CTG is synchronized with its electric generator, and a test of the CTG's overspeed system.
- Steam Blows - During steam blows, steam is passed through the CTG and HRSG to remove all debris that could potentially damage the SCR and oxidation catalysts.
- Minimum Load Tests and Full Load Tests (without SCR Operational) - These tests will occur over several days. During this testing period, the CTG combustor will be tuned to minimize emissions and other checks will be performed.
- Multiple Load Tests (SCR/Oxidation Catalyst Operational at Various Levels) - These tests will occur over several days. By the beginning of this test period, the control systems will be installed and will be tuned to achieve NOx and CO control at design levels.
- Performance Tests (SCR/Oxidation Catalyst at Full Control) - These tests will also occur over a several-day period, with the CTG operating from minimum to maximum load.

NOx and CO emissions during each commissioning activity will be monitored using installed and calibrated (but not certified) continuous emissions monitoring systems. SOx, PM_{10} and VOC emissions will be monitored using measured fuel flow and emission factors based on permit limits.

ATTACHMENT DA5.1-1

SJVAPCD Completeness Letter

San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT

CERTIFIED MAIL

October 2, 2008

Ed Warner
Northern California Power Agency
P.O. Box 1478
Lodi, CA 95241

NCPA CT2
Received by: gw
Date: 10.6.08

Re: Notice of Receipt of Complete Application
Project Number: N-1083490

Dear Mr. Warner:

The San Joaquin Valley Air Pollution Control District (District) has received your Authority to Construct application for the installation of a 255 MW (nominal) electric power generation plant, at 12751 N Thornton Rd, Lodi. Based on our preliminary review, the application appears to be complete. This means that your application contains sufficient information to proceed with our analysis. However, during processing of your application, the District may request additional information to clarify, correct, or otherwise supplement, the information on file.

During the preliminary review analysis, it appeared that you have proposed to use SO_x Emission Reduction Credits (ERCs) to offset a portion (27.8 tons) of PM_{10} emissions increase from this project. Using the proposed inter-pollutant offset ratio of 1.11 to 1, it appears that you have sufficient SO_x ERCs available to overcome the shortfall for PM_{10} emissions. Please note that the District is in the process of determining the appropriate SO_x for PM_{10} offset ratio for the Northern San Joaquin Valley. Should our analysis result in a higher inter-pollutant ratio than what you have proposed, you will be informed, and you may be required to identify additional SO_x credits.

Furthermore, you have recently proposed to use NO_x ERCs to offset a portion (1.0 ton) of VOC emissions increase from this project. Using an inter-pollutant offset ratio of 1.00 to 1, it appears that you have a sufficient amount of NO_x ERCs available to overcome the ERC shortfall for VOCs. At this time, an inter-pollutant offset ratio of 1.00 to 1 appears appropriate. However, if later, the District determines that a higher inter-pollutant offset ratio number is more appropriate, you will be informed, and you may be required to identify additional NO_x credits.

Per District Rule 2201, Section 5.3, Final Action, the District will not be able to issue the final ATC permits until the requirements of the California Environmental Quality Act have been fully satisfied by the Lead Agency.

Per your request, the Authority to Construct will be issued with a Certificate of Conformity (COC). Your project will therefore go for EPA Review per District Rule 2520 for a 45-day period at the conclusion of our analysis, prior to the issuance of the final Authority to Construct permits.

We will begin processing your application as soon as possible. In general, complete applications are processed on a first-come first-served basis.

It is estimated that the project analysis process will take 171.2 hours, and you will be charged at the weighted hourly labor rate in accordance with District Rule 3010. This estimate includes the following major processing steps: Determining Completeness (21.2 hours), Engineering Evaluation (60 hours), BACT Analysis (30 hours), Health Risk Assessment (30 hours), CEQA Analysis (20 hours) and Permit Preparation (10 hours). The current weighted labor rate is $90.00 per hour, but please note that this fee is revised annually to reflect actual costs and therefore may change. No payment is due at this time; an invoice will be sent to you upon completion of this project.

Please note that this letter is not a permit and does not authorize you to proceed with your project. Final approval, if appropriate, will be in the form of ATC permits after application processing is complete. If you have any questions, please contact Mr. Rupi Gill at (209) 557-6400.

Sincerely,
David Warner
Director of Permit Services

for DW

Rupi Gill
Permit Services Manager
DW: jk

NCPA CT2
Received by:
Date: 10.6.08

cc: Gerardo Rios, USEPA Reg. IX
75 Hawthorne St.
San Francisco, CA 94205

Tuan Ngo, California Energy Commission – MS 40
1516 9th Street
Sacramento, CA 95814

Jeff Adkins, Sierra Research
1801 J Street
Sacramento, CA 95814

ATTACHMENT DA5.1-2

Commissioning Activities Quantification and Duration

Table AQ-1
Detailed Emission Calculations for Turbine Commissioning
NCPA Lodi Energy Center

Commissioning Test	Activity	Days	Daily Operation (hrs/day)	GT Firing Rate (MMBtu/hr)	Pollutant	Emission Factor (lbs/MMBtu)	Hourly Emissions (lbs/hr)	Daily Emissions (lbs/day)	Total Emissions During Test (lbs)
FSNL + Ign. Tests	FSNL Operation	2	8	400	NOx		125	1,000.0	2,000.0
					CO		900	7,200.0	14,400.0
					VOC		16.00	128.0	256.0
					SOx	0.0028	1.12	9.0	17.9
					PM10		9.00	72.0	144.0
Steam Blows	Part Load Operation	3	10	1,220	NOx		400	4,000.0	12,000.0
					CO		2000	20,000.0	60,000.0
					VOC		16	160.0	480.0
					SOx	0.0028	3.42	34.2	102.5
					PM10		9.00	90.0	270.0
Part Load Tests	Part Load Operation	4	12	1,220	NOx	0.1088	132.71	1,592.5	6,369.9
					CO		385	4,620.0	18,480.0
					VOC		16.00	192.0	768.0
					SOx	0.00280	3.42	41.0	164.0
					PM10		9.00	108.0	432.0
Full Load Tests without SCR operational	Full Load Operation	4	12	1,885	NOx	0.0326	61.55	738.6	2,954.3
					CO	0.0066	12.46	149.5	598.1
					VOC	0.00180	3.33	40.0	159.8
					SOx	0.00280	5.37	64.4	257.8
					PM10		9.00	108.0	432.0
Multiple Load Tests with SCR at partial control	Startup/Shutdown	5	3	1,885	NOx		100.00	638.7	3,193.3
					CO		900.00	2812.1	14,060.7
					VOC		16.00	78.0	389.9
					SOx	0.0028	5.37	64.4	322.2
					PM10		9.00	108.0	540.0
	Full Load Operation		9		NOx	0.0200	37.63	inc	inc
					CO	0.0066	12.46	inc	inc
					VOC	0.0018	3.33	inc	inc
					SOx	0.0028	5.37	inc	inc
					PM10		9.00	inc	inc
Performance Tests with SCR at full control	Startup/Shutdown	10	3	1,885	NOx		100.00	437.3	4,372.5
					CO		900.00	2825.4	28,253.7
					VOC		16.00	95.9	958.8
					SOx	0.0026	5.37	70.1	701.1
					PM10		9.00	126.0	1,260.0
	Full Load Operation w/ Duct Firing		9	2,107.2	NOx	0.0072	15.25	inc	inc
					CO	0.0066	13.93	inc	inc
					VOC	0.0026	5.32	inc	inc
					SOx	0.0028	6.00	inc	inc
					PM10		11.00	inc	inc

Total Commissioning Hours: 292

1. Emission factors during FSNL and ignition tests
   NOx - based on max expected hourly emission rate of 125 lbs/hr.
   CO - based on startup emission rate of 900 lbs/hr.
   VOC, SOx and PM10 - based on startup emission rates and 1.0 grain S/100 dscf n.g.
2. Emission factors during steam blows
   NOx - based on max expected hourly emission rate of 400 lbs/hr.
   CO - based on maximum expected hourly emission rate of 2000 lbs/hr.
   VOC, SOx and PM10 - based on startup emission rates and 1.0 grain S/100 dscf n.g.
3. Emission factors during part load tests
   NOx - based on estimate for part load test tuning combustor (ppm @ 15% O2) = 30
   CO - based on hourly emission rate used for Crockett Cogeneration plant commissioning period.
   VOC, SOx and PM10 - based on startup emission rates and 1.0 grain S/100 dscf n.g.
4. Emission factors during full load tests without SCR operational
   NOx level in ppmvd @ 15% O_2 = 9
   CO, VOC - based on combustor operating in pre-mix mode (3 ppmc CO and 1.4 ppmc for VOC).
   SOx and PM10 - emission factors based on fuel flow and 1.0 grain S/100 dscf n.g..
5. Emission factors during full load tests with SCR partially operational
   NOx - based information with combustor operating In pre-mix mode and SCR controlling NOx to 5.5 ppmc.
   CO, VOC - based on combustor operating in pre-mix mode (3 ppmc CO, 1.4 ppmc for VOC).
   SOx and PM10 - emission factors based on fuel flow and 1.0 grain S/100 dscf n.g..
6. Emission factors during full load tests with SCR fully operational
   NOx - based on combustor operating in pre-mix mode and SCR operational (2 ppmc NOx).
   CO, VOC - based on combustor operating in pre-mix mode and ox cat operational, 3 hours of startups (3 ppmc CO, 1.4/2.0 ppmc for VOC for 9 hours; 900 lb/hr for CO and 16 lb/hr for VOC during startups).
   SOx and PM10 - emission factors based on fuel flow and 1.0 grain S/100 dscf n.g..
7. Startup and shutdown emission rates unchanged.

Table AQ-2
Emissions During Commissioning
NCPA Lodi Energy Center

Unit	Maximum Hourly and Daily Emissions									
	Peak Hour Emissions					Peak Day Emissions				
	NOx	CO	VOC	SOx	PM10	NOx	CO	VOC	SOx	PM10
	(lbs/hr)					(lbs/day)				
One Gas Turbine in Steam Blow	400.0	2,000.0	16.0	6.0	11.0	4,000	20,000	192.0	70.1	126
Aux. Boiler	0.5	2.37	0.3	0.19	0.47	6.5	28.5	3.3	2.2	5.6
Total	400.5	2,002.4	16.3	6.2	11.5	4,007	20,028	195	72	132

Unit	Total Commissioning Emissions				
	NOx	CO	VOC	SOx	PM10
	(lbs)				
Gas Turbine/HRSG	30,890	135,792	2,853	1,565	3,078
Aux. Boiler (based on 60 hrs)	33	142	16	11	28
Total	30,923	135,935	2,869	1,577	3,106

ATTACHMENT D
SJVAPCD BACT GUIDELINES 1.1.2, 3.4.2 AND 8.3.10

San Joaquin Valley
Unified Air Pollution Control District

Best Available Control Technology (BACT) Guideline 1.1.2*

Last Update: 3/14/2002

Boiler: > 20.0 MMBtu/hr, Natural gas fired, base-loaded or with small load swings.**

Pollutant	Achieved in Practice or contained in the SIP	Technologically Feasible	Alternate Basic Equipment
CO	Natural gas fuel with LPG backup		
NOx	9.0 ppmvd @ 3% O2 (0.0108 lb/MMBtu/hr) Ultra-Low NOx main burner system burner system and a natural gas or LPG fired igniter system (if the igniter system is used to heat the boiler at low fire).	9.0 ppmvd @ 3% O2 (0.0108 lb/MMBtu/hr) Selective Catalytic Reduction, Low Temperature Oxidizer, or equal and a < 30 ppmv NOx@ 3% O2 igniter system (if the igniter system is used to heat the boiler at low fire).	
PM10	Natural gas fuel with LPG backup		
SO	Natural gas fuel with LPG backup		
VOC	Natural gas fuel with LPG backup		

** For the purpose of this determination, "small load swings" are defined as normal operational load fluctuations which are within the operational response range of an Ultra-Low NOx burner system(s).

BACT is the most stringent control technique for the emissions unit and class of source. Control techniques that are not achieved in practice or contained in s a state implementation plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is requried for all determinations that are not achieved in practice or contained in an EPA approved State Implementation Plan.

***This is a Summary Page for this Class of Source - Permit Specific BACT Determinations on Next Page(s)**

San Joaquin Valley
Unified Air Pollution Control District

Best Available Control Technology (BACT) Guideline 3.4.2*

Last Update: 10/1/2002

Gas Turbine - = or > 50 MW, Uniform Load, with Heat Recovery

Pollutant	Achieved in Practice or contained in the SIP	Technologically Feasible	Alternate Basic Equipment
CO	6.0 ppmv @ 15% O2 (Oxidation catalyst, or equal)	4.0 ppmv @ 15% O2 (Oxidation catalyst, or equal)	
NOx	2.5 ppmv dry @ 15% O2 (1-hr average, excluding startup and shutdown), (Selective catalytic reduction, or equal)	2.0 ppmv dry @ 15% O2 (1-hr average, excluding startup and shutdown), (Selective catalytic reduction, or equal)	
PM10	Air inlet filter cooler, lube oil vent coalescer and natural gas fuel, or equal		
SOx	1. PUC-regulated natural gas or 2. Non-PUC-regulated gas with no more that 0.75 grams S/100 dscf, or equal.		
VOC	2.0 ppmv @ 15% O2	1.5 ppmv @ 15% O2	

** Applicability lowered to > 50 MW pursuant to CARB Guidance for Permitting Electrical Generation Technologies. Change effective 10/1/02. Corrected error in applicability to read 50 MW not 50 MMBtu/hr effective 4/1/03.

BACT is the most stringent control technique for the emissions unit and class of source. Control techniques that are not achieved in practice or contained in s a state implementation plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is requried for all determinations that are not achieved in practice or contained in an EPA approved State Implementation Plan.

***This is a Summary Page for this Class of Source - Permit Specific BACT Determinations on Next Page(s)**

San Joaquin Valley
Unified Air Pollution Control District

Best Available Control Technology (BACT) Guideline 8.3.10*

Last Update: 6/19/2000

Cooling Tower - Induced Draft, Evaporative Cooling

Pollutant	Achieved in Practice or contained in the SIP	Technologically Feasible	Alternate Basic Equipment
PM10		Cellular Type Drift Eliminator	

BACT is the most stringent control technique for the emissions unit and class of source. Control techniques that are not achieved in practice or contained in s a state implementation plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is requried for all determinations that are not achieved in practice or contained in an EPA approved State Implementation Plan.

***This is a Summary Page for this Class of Source - Permit Specific BACT Determinations on Next Page(s)**

ATTACHMENT E
TOP-DOWN BACT ANALYSIS (N-2697-5-0, '-6-0, '-7-0)

N-2697-5-0

I. NO_X Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

SJVAPCD BACT Clearinghouse Guideline 3.4.2 lists the following emissions limits or control technologies:

Achieved-in-Practice

- 2.5 ppmvd @ 15% O_2 (1 hr average, excluding startup and shutdown), (Selective catalytic reduction, or equal)

Technologically Feasible

- 2.0 ppmvd @ 15% O_2 (1 hr average, excluding startup and shutdown), (Selective catalytic reduction, or equal)

Alternate Basic Equipment

None

Step 2 - Eliminate Technologically Infeasible Options

All control options listed in step 1 are technologically feasible.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

1. 2.0 ppmvd @ 15% O_2 (1 hr average, excluding startup and shutdown), (Selective catalytic reduction, or equal)
2. 2.5 ppmvd @ 15% O_2 (1 hr average, excluding startup and shutdown), (Selective catalytic reduction, or equal)

Step 4 - Cost Effectiveness Analysis

A cost effectiveness analysis must be performed for all control options in the list from step 3 in the order of their rank to determine the cost effective option with the lowest emissions.

The applicant has proposed to use of a selective catalytic reduction system to achieve less than or equal to 2.0 ppmv NOx @ 15% O_2 (1 hr average, excluding startup and shutdown), (Selective catalytic reduction, or equal). This is the most stringent emission limit listed in Step 3 above. Therefore, in accordance with District policy APR-1305

(BACT), Section IX.D, a cost effective analysis is not necessary and no further discussion is required.

Step 5 - Select BACT

BACT for the gas turbine system is to achieve 2.0 ppmvd @ 15% O_2 or less (1 hr average, excluding startup and shutdown) using an SCR or equal technology.

NCPA has proposed to achieve 2.0 ppmv @ 15% O_2 or less (1 hr average, excluding startup and shutdown) using an SCR system. Therefore, BACT requirements are satisfied.

II. CO Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

SJVAPCD BACT Clearinghouse Guideline 3.4.2 lists the following emissions limits or control technologies:

Achieved-in-Practice

- 6.0 ppmv @ 15% O_2 (3-hour rolling average, except during startup/shutdown) with an Oxidation Catalyst and natural gas fuel

Technologically Feasible

- 4.0 ppmv @ 15% O_2 (3-hour rolling average, except during startup/shutdown) with an Oxidation Catalyst and natural gas fuel

Alternate Basic Equipment

None

Step 2 - Eliminate Technologically Infeasible Options

All control options listed in step 1 are technologically feasible.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

1. 4.0 ppmv @ 15% O_2 (3-hour rolling average, except during startup/shutdown) with an Oxidation Catalyst and natural gas fuel.

2. 6.0 ppmv @ 15% O_2 (3-hour rolling average, except during startup/shutdown) with an Oxidation Catalyst and natural gas fuel.

Step 4 - Cost Effective Analysis

A cost effectiveness analysis must be performed for all control options in the list from step 3 in the order of their rank to determine the cost effective option with the lowest emissions.

The applicant has proposed to use of an oxidation catalyst to achieve less than or equal to 3.0 ppmvd CO @ 15% O_2 (3-hr rolling average, excluding startup and shutdown). The proposed limit is more stringent than the emission limits listed in Step 3 above. Therefore, in accordance with District policy APR-1305 (BACT), Section IX.D, a cost effective analysis is not necessary and no further discussion is required.

Step 5 - Select BACT

BACT for the gas turbine system is to achieve 4.0 ppmvd @ 15% O_2 or less (3-hour rolling average, except during startup/shutdown) with an Oxidation Catalyst and natural gas fuel.

NCPA has proposed to achieve 3.0 ppmvd @ 15% O_2 or less (3-hour rolling average, except during startup/shutdown) using an oxidation catalyst and natural gas fuel. Therefore, BACT requirements are satisfied.

III. VOC Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

SJVAPCD BACT Clearinghouse Guideline 3.4.2 lists the following emissions limits or control technologies:

<u>Achieved-in-Practice</u>

- 2.0 ppmvd VOC @ 15% O_2

<u>Technologically Feasible</u>

- 1.5 ppmvd VOC @ 15% O_2

<u>Alternate Basic Equipment</u>

None

Step 2 - Eliminate Technologically Infeasible Options

All control options listed in step 1 are technologically feasible.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

1. 1.5 ppmvd @ 15% O_2
2. 2.0 ppmvd @ 15% O_2

Step 4 - Cost Effectiveness Analysis

A cost effectiveness analysis must be performed for all control options in the list from step 3 in the order of their rank to determine the cost effective option with the lowest emissions.

The applicant has proposed to meet 2.0 ppmvd @ 15% O_2 on 3-hour average basis with duct firing, and 1.4 ppmvd @ 15% O2 on 3-hour average basis with no duct firing. Please note that 1.5 ppmvd @ 15% O2 is added to the BACT guideline, while processing Aera Energy's project S-1000170, in year 2000. Aera's project was never constructed. BACT analysis prepared for Aera's project does not clearly indicate if the VOC concentrations (referenced as methane) of 1.5 ppmvd @ 15% O_2 was guaranteed with duct firing or without duct firing. Moreover, recently processed permit C-3953-10 for Avenal Power Center contains emission limits of 2.0 ppmvd @ 15% O_2 with duct firing and 1.4 ppmvd @ 15% O_2 without duct firing for VOC emissions.

Based on the above discussion, it is determined that it is acceptable to use the proposed VOC concentrations for satisfying the BACT requirements without performing a cost-analysis for the technologically feasible option.

Step 5 - Select BACT

BACT for the gas turbine system is to achieve less than or equal to 2.0 ppmv @ 15% O_2.

NCPA has proposed to achieve VOC concentrations of less than or equal to 2.0 ppmv @ 15% O_2 with duct firing, and 1.4 ppmv @ 15% O2 with no duct firing. Therefore, BACT requirements are satisfied.

IV. PM_{10} Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

SJVAPCD BACT Clearinghouse Guideline 3.4.2 lists the following emissions limits or control technologies:

<u>Achieved-in-Practice</u>

- Air inlet filter, lube oil vent coalescer and natural gas fuel or equal

Technologically Feasible

None

Alternate Basic Equipment

None

Step 2 - Eliminate Technologically Infeasible Options

All of the listed controls are considered technologically feasible for this application.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

1. Air inlet filter, lube oil vent coalescer and natural gas fuel or equal

Step 4 - Cost Effectiveness Analysis

A cost effectiveness analysis must be performed for all control options in the list from step 3 in the order of their rank to determine the cost effective option with the lowest emissions.

The proposed CTG will be equipped with an inlet air filter, lube oil vent coalescer and be operated on natural gas fuel. This is the only ranking control option listed in Step 3 above. Therefore, in accordance with District policy APR 1305 (BACT), Section IX.D, a cost effective analysis is not necessary and no further discussion is required.

Step 5 - Select BACT

BACT for the gas turbine system is to use an air inlet filter, lube oil vent coalescer and natural gas fuel or equal.

The proposed turbine will be equipped with an air inlet filter, lube oil vent coalescer, and will be operated using natural gas fuel. Therefore, BACT requirements are satisfied.

V. SO_X Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

SJVAPCD BACT Clearinghouse Guideline 3.4.2 lists the following emissions limits or control technologies:

Achieved-in-Practice

PUC-regulated natural gas fuel; or Non-PUC-regulated gas with no more than 0.75 grains S/100 dscf, or equal

Technologically Feasible

None

Alternate Basic Equipment

None

Step 2 - Eliminate Technologically Infeasible Options

All of the listed controls are considered technologically feasible for this application.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

1. PUC-regulated natural gas fuel
2. Non-PUC-regulated gas with no more than 0.75 grains S/100 dscf, or equal

Step 4 - Cost Effectiveness Analysis

A cost effectiveness analysis must be performed for all control options in the list from step 3 in the order of their rank to determine the cost effective option with the lowest emissions.

The applicant has proposed to use PUC-regulated natural gas fuel. Therefore, in accordance with District policy APR 1305 (BACT), Section IX.D, a cost effective analysis is not necessary and no further discussion is required.

Step 5 - Select BACT

BACT for the gas turbine system is to use PUC-regulated natural gas or PUC quality gas with 0.75 grains S/100 dscf.

The applicant has proposed to use PUC-regulated natural gas fuel. Therefore, the BACT requirements are satisfied.

N-2697-6-0

PM_{10} Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

SJVAPCD BACT Clearinghouse Guideline 8.3.10 lists the following emissions limits or control technologies:

Achieved-in-Practice

None

Technologically Feasible

Cellular type drift eliminator

Alternate Basic Equipment

None

Step 2 – Eliminate Technologically Infeasible Options

All of the listed controls are considered technologically feasible for this application.

Step 3 – Rank Remaining Control Technologies by Control Effectiveness

1. Cellular type drift eliminator

Step 4 - Cost Effectiveness Analysis

A cost effectiveness analysis must be performed for all control options in the list from step 3 in the order of their rank to determine the cost effective option with the lowest emissions.

The proposed cooling tower will be equipped with a high efficiency drift eliminators. This is the only ranking control option listed in Step 3 above. Therefore, in accordance with District policy APR 1305 (BACT), Section IX.D, a cost effective analysis is not necessary and no further discussion is required.

Step 5 - Select BACT

BACT for the gas turbine system is to use cellular type drift eliminators. The proposed cooling tower will be equipped with a high efficiency drift eliminators. Therefore, BACT requirements are satisfied.

N-2697-7-0

I. NO_X Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

SJVAPCD BACT Clearinghouse Guideline 1.1.2 lists the following emissions limits or control technologies:

Achieved-in-Practice

- 9.0 ppmvd @ 3% O2 (0.0108 lb/MMBtu) Ultra-Low NOx main burner system and a natural gas or LPG fired igniter system (if the igniter system is used to heat the boiler at low fire)

Technologically Feasible

- 9.0 ppmvd @ 3% O2 (0.0108 lb/MMBtu) Selective Catalytic Reduction, Low Temperature Oxidizer, or equal and a < 30 ppmv NO_X @ 3% O2 igniter system (if the igniter system is used to heat the boiler at low fire)

Alternate Basic Equipment

None

Step 2 - Eliminate Technologically Infeasible Options

All control options listed in step 1 are technologically feasible.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

1. 9.0 ppmvd @ 3% O2 (0.0108 lb/MMBtu) Selective Catalytic Reduction, Low Temperature Oxidizer, or equal and a < 30 ppmv NO_X @ 3% O2 igniter system (if the igniter system is used to heat the boiler at low fire)

2. 9.0 ppmvd @ 3% O2 (0.0108 lb/MMBtu) Ultra-Low NOx main burner system and a natural gas or LPG fired igniter system (if the igniter system is used to heat the boiler at low fire)

Step 4 - Cost Effectiveness Analysis

A cost effectiveness analysis must be performed for all control options in the list from step 3 in the order of their rank to determine the cost effective option with the lowest emissions.

The applicant has proposed to achieve less than 9.0 ppmvd NOx @ 3% O_2. The proposed emission concentrations are more stringent that the technologically and achieved-in-practice controls. Therefore, in accordance with District policy APR 1305 (BACT), Section IX.D, a cost effective analysis is not necessary and no further discussion is required.

Step 5 - Select BACT

BACT for the emission unit is to achieve less than 9.0 ppmvd @ 3% O_2. NCPA has proposed to meet less than or equal to 7.0 ppmvd NOx @ 3% O2. Therefore, BACT requirements are satisfied.

II. CO Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

SJVAPCD BACT Clearinghouse Guideline 1.1.2 lists the following emissions limits or control technologies:

<u>Achieved-in-Practice</u>

Natural gas fuel with LPG backup

<u>Technologically Feasible</u>

Cellular type drift eliminator

<u>Alternate Basic Equipment</u>

None

Step 2 - Eliminate Technologically Infeasible Options

All of the listed controls are considered technologically feasible for this application.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

1. Natural gas fuel with LPG backup

Step 4 - Cost Effectiveness Analysis

A cost effectiveness analysis must be performed for all control options in the list from step 3 in the order of their rank to determine the cost effective option with the lowest emissions.

The applicant has proposed to use natural gas fuel. Therefore, in accordance with District policy APR 1305 (BACT), Section IX.D, a cost effective analysis is not necessary and no further discussion is required.

Step 5 - Select BACT

BACT for the emission unit is to use natural gas fuel. NCPA is proposing to use natural gas fuel; therefore, BACT requirements are satisfied.

III. VOC Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

SJVAPCD BACT Clearinghouse Guideline 1.1.2 lists the following emissions limits or control technologies:

<u>Achieved-in-Practice</u>

Natural gas fuel with LPG backup

<u>Technologically Feasible</u>

Cellular type drift eliminator

<u>Alternate Basic Equipment</u>

None

Step 2 - Eliminate Technologically Infeasible Options

All of the listed controls are considered technologically feasible for this application.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

1. Natural gas fuel with LPG backup

Step 4 - Cost Effectiveness Analysis

A cost effectiveness analysis must be performed for all control options in the list from step 3 in the order of their rank to determine the cost effective option with the lowest emissions.

The applicant has proposed to use natural gas fuel. Therefore, in accordance with District policy APR 1305 (BACT), Section IX.D, a cost effective analysis is not necessary and no further discussion is required.

Step 5 - Select BACT

BACT for the emission unit is to use natural gas fuel. NCPA is proposing to use natural gas fuel; therefore, BACT requirements are satisfied.

IV. PM_{10} Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

SJVAPCD BACT Clearinghouse Guideline 1.1.2 lists the following emissions limits or control technologies:

Achieved-in-Practice

Natural gas fuel with LPG backup

Technologically Feasible

Cellular type drift eliminator

Alternate Basic Equipment

None

Step 2 - Eliminate Technologically Infeasible Options

All of the listed controls are considered technologically feasible for this application.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

1. Natural gas fuel with LPG backup

Step 4 - Cost Effectiveness Analysis

A cost effectiveness analysis must be performed for all control options in the list from step 3 in the order of their rank to determine the cost effective option with the lowest emissions.

The applicant has proposed to use natural gas fuel. Therefore, in accordance with District policy APR 1305 (BACT), Section IX.D, a cost effective analysis is not necessary and no further discussion is required.

Step 5 - Select BACT

BACT for the emission unit is to use natural gas fuel. NCPA is proposing to use natural gas fuel; therefore, BACT requirements are satisfied.

V. SOx Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

SJVAPCD BACT Clearinghouse Guideline 1.1.2 lists the following emissions limits or control technologies:

<u>Achieved-in-Practice</u>

Natural gas fuel with LPG backup

<u>Technologically Feasible</u>

Cellular type drift eliminator

<u>Alternate Basic Equipment</u>

None

Step 2 - Eliminate Technologically Infeasible Options

All of the listed controls are considered technologically feasible for this application.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

2. Natural gas fuel with LPG backup

Step 4 - Cost Effectiveness Analysis

A cost effectiveness analysis must be performed for all control options in the list from step 3 in the order of their rank to determine the cost effective option with the lowest emissions.

The applicant has proposed to use natural gas fuel. Therefore, in accordance with District policy APR 1305 (BACT), Section IX.D, a cost effective analysis is not necessary and no further discussion is required.

Step 5 - Select BACT
BACT for the emission unit is to use natural gas fuel. NCPA is proposing to use natural gas fuel; therefore, BACT requirements are satisfied.

ATTACHMENT F
HEALTH RISK ASSESSMENT AND AMBIENT AIR QUALITY ANALYSIS

San Joaquin Valley Air Pollution Control District
Risk Management Review

To: Jag Kahlon – Permit Services

From: Cheryl Lawler – Technical Services

Date: November 17, 2008

Facility Name: Northern California Power Agency (NCPA)

Location: 12745 North Thornton Road, Lodi

Application #(s): N-2697-5-0, 6-0, & 7-0

Project #: N-1083490

A. RMR SUMMARY

RMR Summary					
Categories	**NG Turbine & NG Duct Burner (Unit 5-0)**	**Seven-Cell Cooling Tower (Unit 6-0)**	**NG Boiler (Unit 7-0)**	**Project Totals**	**Facility Totals**
Prioritization Score	2.31	**0.00***	1.40	3.71	>1
Acute Hazard Index	0.02	N/A	0.05	0.07	0.07
Chronic Hazard Index	0.00	N/A	0.00	0.00	0.00
Maximum Individual Cancer Risk	**4.57E-07**	N/A	**3.34E-07**	7.91E-07	7.91E-07
T-BACT Required?	**No**	**No**	**No**		
Special Permit Conditions?	**No**	**No**	**No**		

*The prioritization score was determined to be insignificant (less than 0.05); therefore, the effective prioritization score for this unit is considered to be 0.00.

B. RMR REPORT

I. Project Description

Technical Services received a request on October 2, 2008, to perform an Ambient Air Quality Analysis and a Risk Management Review for the installation of a 255 MW (nominal), natural gas, combined-cycle, electric generation plant that consists of a natural gas combustion turbine generator rated at a combined maximum heat input rate of 1885.3 MMBtu/hr for dry-low NOX combustors, a heat recovery steam generator equipped with a natural gas direct-fired duct burner rated at a maximum heat input rate of 222 MMBtu/hr, a steam turbine generator, a seven-cell mechanical draft cooling tower and associated equipment, a deaerating surface condenser to convert the steam from the low-pressure section of the steam turbine generator into water for re-use, and a natural gas auxiliary boiler rated at a maximum heat input rate of 65 MMBtu/hr.

II. Analysis

For the Risk Management Review, toxic emissions from the turbine, duct burner, and boiler were calculated using Ventura County emission factors. Toxic emissions from biocide products used in the cooling towers were calculated after reviewing MSDS sheets to determine the speciation of hazardous air pollutants found in the biocides. In accordance with the District's *Risk Management Policy for Permitting New and Modified Sources* (APR 1905-1, March 2, 2001), risks from the proposed project were prioritized using the procedures in the 1990 CAPCOA Facility Prioritization Guidelines and incorporated in the District's HEART's database.

For Units 5-0 and 7-0, the prioritization scores were greater than 1.0 (see RMR Summary Table); therefore, a refined health risk assessment was required and performed for each unit. AERMOD was used, with the parameters outlined below and meteorological data from Stockton to determine the maximum dispersion factors at the nearest residential and business receptors. These dispersion factors were input in the HARP model to calculate the chronic and acute hazard indices and the carcinogenic risk for each unit.

For Unit 6-0, the prioritization was less than 1.0 (see RMR Summary Table). Therefore, no further analysis was necessary.

The following parameters were used for the review:

Analysis Parameters Unit 5-0			
Source Type	Point	**Closest Receptor (m)**	30.95
Stack Height (m)	45.72	**Closest Receptor Type**	Business
Inside Diameter (m)	5.78	**Project Location Type**	Rural
Gas Exit Temperature (K)	351	**Stack Gas Velocity (m/s)**	18.78
Analysis Parameters Unit 7-0			
Source Type	Point	**Closest Receptor (m)**	12.72
Stack Height (m)	12.19	**Closest Receptor Type**	Business
Inside Diameter (m)	0.91	**Project Location Type**	Rural
Gas Exit Temperature (K)	464	**Stack Gas Velocity (m/s)**	14.99
Analysis Parameters Unit 6-0 (Cooling Tower)			
Project Location Type	Rural	**Closest Receptor (m)**	Varies for each Tower Cell
		Closest Receptor Type	Business

Technical Services also performed modeling for criteria pollutants CO, NOx, SOx, and PM_{10}; as well as the RMR.

For Unit 5-0, the emission rates used for criteria pollutant modeling were 2000 lb/hr CO, 400 lb/hr NOx, 6 lb/hr SOx, and 11 lb/hr PM_{10}. For this unit, the emission rates were determined after reviewing the turbine's startup and shutdown hours, base and peak hours, and commissioning hours.

For Unit 6-0, the emission rate used for criteria pollutant modeling was 0.06 lb/hr PM_{10} for each cooling tower cell.

For Unit 7-0, the emission rates used for criteria pollutant modeling were 2.40 lb/hr CO, 0.55 lb/hr NOx, 0.19 lb/hr SOx, and 0.49 lb/hr PM_{10}.

The results from the Criteria Pollutant Modeling are as follows:

Criteria Pollutant Modeling Results*
Values are in μg/m^3

Units 5-0, 6-0, & 7-0	1 Hour	3 Hours	8 Hours	24 Hours	Annual
CO	Pass	X	Pass	X	X
NO_x	Pass	X	X	X	Pass
SO_x	Pass	Pass	X	Pass	Pass
PM_{10}	X	X	X	Pass[1]	Pass[1]

*Results were taken from the attached PSD spreadsheets.
[1]The criteria pollutants are below EPA's level of significance as found in 40 CFR Part 51.165 (b)(2).

III. Conclusion

Unit 5-0

The criteria modeling runs indicate the emissions from the proposed equipment will not cause or significantly contribute to a violation of a State or National AAQS.

The acute and chronic indices are below 1.0; and the maximum individual cancer risk associated with the unit is **4.57E-07,** which is less than the 1 in a million threshold. In accordance with the District's Risk Management Policy, the unit is approved **without** Toxic Best Available Control Technology (T-BACT).

Unit 6-0

The criteria modeling runs indicate the emissions from the proposed equipment will not cause or significantly contribute to a violation of a State or National AAQS.

The prioritization score for this unit is not above 1.0. In accordance with the District's Risk Management Policy, the unit is approved **without** Toxic Best Available Control Technology (T-BACT).

Unit 7-0

The criteria modeling runs indicate the emissions from the proposed equipment will not cause or significantly contribute to a violation of a State or National AAQS.

The acute and chronic indices are below 1.0; and the maximum individual cancer risk associated with the unit is **3.34E-07,** which is less than the 1 in a million threshold. In accordance with the District's Risk Management Policy, the unit is approved **without** Toxic Best Available Control Technology (T-BACT).

These conclusions are based on the data provided by the applicant and the project engineer. Therefore, this analysis is valid only as long as the proposed data and parameters do not change.

Ester Davila

From:	Jagmeet Kahlon
Sent:	Thursday, October 02, 2008 4:36 PM
To:	Ester Davila
Cc:	Rupi Gill
Subject:	RMR for Northern California Power Agency's (NCPA) Project N-1083490
Attachments:	N2697, 1083490_RMR.doc

Ester,

Please process the attached RMR for a 255 MW electric generation plant. NCPA have included a CD with the application package that includes some modeling files. I will send you the CD through inter-office mail. Please let me know if you have any questions or you need additional information related to this project.

Thanks,
Jagmeet
ext. 6452

ENGINEERING HRA
REVIEW & MODELING REQUEST

Facility Name:	Northern California Power Agency (NCPA)	Process Engineer:	Jag Kahlon
Mailing Address:	P.O. Box 1478 Lodi, CA 95241	Life Of Project:	
Location:	12745 North Thornton Road Lodi, California		
		Processing Staff:	
Contact Name:	Jeff Adkins, Consultant	Start Date:	
Telephone:	(916) 444-6666	Completed Date:	
Application #:	N-2697-5-0, '-6-0, '-7-0	Reviewed By:	
Project #:	N-1083490	Date:	

FAX OR MAIL TO TECHNICAL SERVICES SUPERVISOR

HRA Information Checklist	Yes	No
Is all of the following information provided (as applicable)? ☒ Receptor distances ☒ Stack velocity ☒ Stack height ☒ Stack temperature ☒ Emission/Usage Rates (hour/annual) ☒ Hours of Operation ☐ MSDS ☐ Other (for area sources)	☒	☐ Incomplete (Otherwise, explain under Comments).
Supplemental Application Form attached (as applicable)?	☐ Only HRA cover page is required.	☒ Submit complete HRA Request Form.
Is it obvious that notification is required (NSR, COC, or school)? ☒ NSR (Public Notice): *Distances to the fence line in all four directions are required* ☒ COC (EPA Notice) ☐ School Notice	☒	☐
Has the applicant requested reimbursable overtime processing?	☐ • Get approval from your supervisor. • Send HRA request to Tech Services before deeming complete.	☒
Supervisor's signature for expedited processing:		
Comments and References:		

SCREENING HRA REQUEST

I. Project Description:

Northern California Power Agency (NCPA) is requesting Authority to Construct (ATC) for the installation of a 255 MW (nominal), natural gas-fired, combined-cycle, electric generation plant that consists of a General Electric's (GE) natural gas-fired "Rapid Response" Frame 7FA (or equivalent) combustion turbine-generator (CTG) rated at combined maximum heat input rate of 1,885.3 MMBtu/hour for dry-low NOx combustors, a heat recovery steam generator (HRSG) equipped with natural gas direct-fired duct burners rated at a maximum heat input rate of 222 MMBtu/hour, a steam turbine generator (STG), a seven-cell mechanical draft cooling tower and associated equipment, a deaerating surface condenser to convert the steam from low-pressure section of the STG into water for re-use in HRSG feed water, and a natural gas-fired auxiliary boiler rated at a maximum heat input rate of 65 MMBtu/hour for GE's "Rapid Response" system.

NCPA possess a Title V permit, and requested that the project is processed with Certificate of Conformity (COC), which is EPA's 45-day review prior to the issuance of final ATC.

II Receptor Location(s):

N-2697-5-0:

Receptor Description (Units)	Distance From Source (Units)	
Residence	2,323.2 feet - North	708.1114 Meters
Business	101.53 feet - Northeast	30.9463 Meters

N-2697-6-0:

Please see the attached site map, as each cooling tower cell may result in different business and residence receptor distance.

N-2697-7-0:

Receptor Description (Units)	Distance From Source (Units)	
Residence	2,323.2 feet - North	708.1114 Meters
Business	41.74 feet - Northeast	12.7224 Meters

TURBINE (5-0)

NOX

1 HR/lbs	Annual / lbs
400 lbs	30 hrs @ 400 lbs
	16 hrs @ 125 lbs
	48 hrs @ 132.71 lbs
	468 hrs @ 100 lbs
	48 hrs @ 61.55
	15 hrs @ 100
	9 hrs @ 37.63
	30 hrs @ 100
	8096 hrs @ 15.25
	198,427.15 lbs

For AAQA

CO

1 HR/lbs	8 HR/lbs
2000 lbs	2000 lbs

SOX

1 HR/lbs	3 HR	24 HRs	Annual/ lbs
6 lbs	6 lbs	6 lbs	16 hrs @ 1.12 lbs
			30 hrs @ 3.42 lbs
			48 hrs @ 3.42
			48 hrs @ 5.37
			15 hrs @ 5.37
			9 hrs @ 5.37
			30 hrs @ 5.37
			9 hrs @ 6.00
			468 hrs @ 5.37
			8087 hrs @ 6.00
			51,921.58 lbs

PM10

24 HR/lbs	Annual / lbs
11 lbs	83,840 lbs

III. Process Rate Or Substances To Be Modeled:

N-2967-5-0 (CTG/HRSG): (Turbine)

startup + shutdowns each 1 hr

use highest one

Category 6 hr	Hourly (lb/hour)	PE2 (lb/day)	Q1 (lb)	Q2 (lb)	Q3 (lb)	Q4 (lb)	PE2 (lb/year)
Potential NO_X Emissions							
Gas Turbine, startups/shutdowns	160.00 (max) 100.00 (avg)	600.0 3/3	14,200 71/71	14,200 71/71	7,600 38/38	10,800 54/54	46,800 468 hrs
Gas Turbine, Base	13.64	81.8	16,150	16,477	10,912	14,186	57,725
Gas Turbine, Peak	15.25	183.0	5,338	5,338	16,775	10,675	38,126
Total:		**864.8**	35,688	36,015	35,287	35,661	**142,651**

Category	Hourly (lb/hour)	PE2 (lb/day)	Q1 (lb)	Q2 (lb)	Q3 (lb)	Q4 (lb)	PE2 (lb/year)
Potential CO Emissions							
Gas Turbine, startups/shutdowns	900.00	5,400.0	127,800	127,800	68,400	97,200	421,200
Gas Turbine, Base	12.46	74.8	14,753	15,052	9,968	12,958	52,731
Gas Turbine, Peak	13.93	167.2	4,876	4,876	15,323	9,751	34,826
Total:		**5,642.0**	147,429	147,728	93,691	119,909	**508,757**

Category	Hourly (lb/hour)	PE2 (lb/day)	Q1 (lb)	Q2 (lb)	Q3 (lb)	Q4 (lb)	PE2 (lb/year)
Potential VOC Emissions							
Gas Turbine, startups/shutdowns	16.00	96.0	2,272	2,272	1,216	1,728	7,488
Gas Turbine, Base	3.33	20.0	3,943	4,023	2,664	3,463	14,093
Gas Turbine, Peak	5.32	63.8	1,862	1,862	5,852	3,724	13,300
Total:		**179.8**	8,077	8,157	9,732	8,915	**34,881**

Category	Hourly (lb/hour)	PE2 (lb/day)	Q1 (lb)	Q2 (lb)	Q3 (lb)	Q4 (lb)	PE2 (lb/year)
Potential NH_3 Emissions							
Gas Turbine, startups/shutdowns	25.25	151.5	3,586	3,586	1,919	2,727	11,818
Gas Turbine, Base	25.25	151.5	42,117	42,723	26,058	35,350	146,248
Gas Turbine, Peak	28.23	338.8	9,881	9,881	31,053	19,761	70,576
Total:		**641.8**	55,584	56,190	59,030	57,838	**228,642**

Category	Hourly (lb/hour)	PE2 (lb/day)	Q1 (lb)	Q2 (lb)	Q3 (lb)	Q4 (lb)	PE2 (lb/year)
Potential PM_{10} Emissions							
Gas Turbine, startups/shutdowns	9.00	54.0	1,278	1,278	684	972	4,212 468 hrs
Gas Turbine, Base	9.00	54.0	15,012	15,228	9,288	12,600	52,128
Gas Turbine, Peak	11.00	132.0	3,850	3,850	12,100	7,700	27,500
Total:	hourly	**240.0**	20,140	20,356	22,072	21,272	**83,840** Annual

Per Leland, use these for Total PM10.

Potential SO_X Emissions							
Category	Hourly (lb/hour)	PE2 (lb/day)	Q1 (lb)	Q2 (lb)	Q3 (lb)	Q4 (lb)	PE2 (lb/year)
Gas Turbine, startups/shutdowns	5.37	32.2	763	763	408	580	2,514
Gas Turbine, Base	5.37	32.2	8,957	9,086	5,542	7,518	31,103
Gas Turbine, Peak	6.00	72.0	2,100	2,100	6,600	4,200	15,000
Total:		**136.4**	11,820	11,949	12,550	12,298	**48,617**

468 hrs
5,794.99
2500
1400
329699

N-2697-6-0 (Cooling Tower):

$$PE2 = 0.45\frac{\text{lb - PM}_{10}}{\text{hr}};10.8\frac{\text{lb - PM}_{10}}{\text{day}};3,942\frac{\text{lb - PM}_{10}}{\text{yr}} \rightarrow \text{(Total all 7 Towers combined)}$$

$\searrow$ Each Tower = 0.0643 lb/Hr & 563.1429 lb/YR

N-2697-7-0 (Boiler):

Potential Emissions for NOx, CO, VOC, PM_{10}, SOx							
Pollutant	Hourly (lb/hour)	PE2 (lb/day)	Q1 (lb)	Q2 (lb)	Q3 (lb)	Q4 (lb)	PE2 (lb/year)
NOx	0.55	6.6	78	78	42	60	258
CO	2.40	28.8	341	341	182	259	1,123
VOC	0.27	3.3	39	39	21	30	129
PM_{10}	0.49	5.9	70	70	38	53	231
SO_x	0.19	2.2	26	26	14	20	86

IV. Project Location (Select One): Urban (1) or Rural (2)
2. Rural - area of sparse population

V. Point Sources:

N-2697-5-0 (CTG/HRSG): (Turbine)

The numbers in the following table are taken from the supplemental application forms.

Stack Height (Units)	Inside Diameter (Units)	Gas Exit Velocity (Units)	Gas Exit Temperature (Units)
150 feet	227.6 inches	1,044,503 acfm	172 F

N-2697-6-0 (Cooling Tower):

There are seven cells in a cooling tower system. Information for **each** cell is given in the following table. These numbers are taken from Table 5.1B-4 of the application package.

Stack Height (Units)	Inside Diameter (Units)	Gas Exit Velocity (Units)	Gas Exit Temperature (Units)
45.8 feet	168 inches	185,280 acfm	86.4 F

N-2697-7-0 (Boiler):

The numbers in the following table are taken from the supplemental application forms.

Stack Height (Units)	Inside Diameter (Units)	Gas Exit Velocity (Units)	Gas Exit Temperature (Units)
40 feet	36 inches	20,866.7 acfm	375 F

VI: Area Sources[1]:

Area Parameters:

Release Height[2] (Units)	Length Of Side (Units)

1. An area source is defined as in an area with four equal sides.
2. Release height is defined as the physical height of the source. For example, if a sump has a three meter brim surrounding it. The physical height of the sump is three meters. Height is measured from the ground to the top of the source.

Cheryl Lawler

From: Jagmeet Kahlon
Sent: Wednesday, October 22, 2008 4:48 PM
To: Cheryl Lawler
Subject: FW: NCPA Lodi Energy Center, Project N-1083490
Attachments: LEC_Supplement_Oct08_Air.pdf

Cheryl,

Attached document contains the commissioning emission rates. If you have any questions, please call me.

Thanks,
Jagmeet
ext. 6452

From: Nancy L. Matthews [mailto:NMatthews@sierraresearch.com]
Sent: Wednesday, October 22, 2008 3:28 PM
To: Jagmeet Kahlon
Cc: Nancy L. Matthews; Jeff Adkins
Subject: NCPA Lodi Energy Center, Project N-1083490

Jag--

Attached per your request is an assessment of expected emissions from the NCPA Lodi Energy Center project during the commissioning phase. This information will also be submitted to the CEC on Friday.

I hope this provides the information you are looking for. If you have any questions regarding this information or about any other aspect of the project, please feel free to contact Jeff or me.

Thank you--

Nancy

5.1 Air Quality

2. Compliance Determination (Appendix B (g) (8) (A))

The information necessary for the air pollution control district where the project is located to complete a Determination of Compliance.

Information required to make AFC conform with regulations:

Please provide a copy of the District's Notice of Completeness.

Response: A copy of the District's completeness letter dated October 2, 2008, was docketed on October 23, 2008. A copy of the letter is provided as Attachment DA 5.1-1.

3. Emission Quantification (Appendix B(g) (8) (F)(ii)

A description of the project's planned initial commissioning phase, which is the phase between the first firing of emissions sources and the commercial operations date, including the types and durations of equipment tests, criteria pollutant emissions, and monitoring techniques to be used during such tests.

Information required to make AFC conform with regulations:

Please provide description, duration and quantification of emissions for each commissioning activity.

Please provide method(s) to monitor the emissions of each commissioning activity.

Response: Each commissioning activity is described below. The expected duration and quantification of emissions from each commissioning activity are provided in Tables AQ-1 and AQ-2, attached as Attachment DA 5.1--2.

- Full Speed No Load Tests (FSNL) - This activity includes a test of the gas turbine ignition system, a test to assure that the CTG is synchronized with its electric generator, and a test of the CTG's overspeed system.
- Steam Blows - During steam blows, steam is passed through the CTG and HRSG to remove all debris that could potentially damage the SCR and oxidation catalysts.
- Minimum Load Tests and Full Load Tests (without SCR Operational) - These tests will occur over several days. During this testing period, the CTG combustor will be tuned to minimize emissions and other checks will be performed.
- Multiple Load Tests (SCR/Oxidation Catalyst Operational at Various Levels) - These tests will occur over several days. By the beginning of this test period, the control systems will be installed and will be tuned to achieve NOx and CO control at design levels.
- Performance Tests (SCR/Oxidation Catalyst at Full Control) - These tests will also occur over a several-day period, with the CTG operating from minimum to maximum load.

NOx and CO emissions during each commissioning activity will be monitored using installed and calibrated (but not certified) continuous emissions monitoring systems. SOx, PM_{10} and VOC emissions will be monitored using measured fuel flow and emission factors based on permit limits.

ATTACHMENT DA5.1-1

SJVAPCD Completeness Letter

San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT

CERTIFIED MAIL

October 2, 2008

Ed Warner
Northern California Power Agency
P.O. Box 1478
Lodi, CA 95241

NCPA CT2
Received by: [handwritten initials]
Date: 10.6.08

Re: Notice of Receipt of Complete Application
Project Number: N-1083490

Dear Mr. Warner:

The San Joaquin Valley Air Pollution Control District (District) has received your Authority to Construct application for the installation of a 255 MW (nominal) electric power generation plant, at 12751 N Thornton Rd, Lodi. Based on our preliminary review, the application appears to be complete. This means that your application contains sufficient information to proceed with our analysis. However, during processing of your application, the District may request additional information to clarify, correct, or otherwise supplement, the information on file.

During the preliminary review analysis, it appeared that you have proposed to use SO_x Emission Reduction Credits (ERCs) to offset a portion (27.8 tons) of PM_{10} emissions increase from this project. Using the proposed inter-pollutant offset ratio of 1.11 to 1, it appears that you have sufficient SO_x ERCs available to overcome the shortfall for PM_{10} emissions. Please note that the District is in the process of determining the appropriate SO_x for PM_{10} offset ratio for the Northern San Joaquin Valley. Should our analysis result in a higher inter-pollutant ratio than what you have proposed, you will be informed, and you may be required to identify additional SO_x credits.

Furthermore, you have recently proposed to use NO_x ERCs to offset a portion (1.0 ton) of VOC emissions increase from this project. Using an inter-pollutant offset ratio of 1.00 to 1, it appears that you have a sufficient amount of NO_x ERCs available to overcome the ERC shortfall for VOCs. At this time, an inter-pollutant offset ratio of 1.00 to 1 appears appropriate. However, if later, the District determines that a higher inter-pollutant offset ratio number is more appropriate, you will be informed, and you may be required to identify additional NO_x credits.

Per District Rule 2201, Section 5.3, Final Action, the District will not be able to issue the final ATC permits until the requirements of the California Environmental Quality Act have been fully satisfied by the Lead Agency.

Seyed Sadredin
Executive Director/Air Pollution Control Officer

Northern Region
4800 Enterprise Way
Modesto, CA 95356-8718
Tel: (209) 557-6400 FAX: (209) 557-6475

Central Region (Main Office)
1990 E. Gettysburg Avenue
Fresno, CA 93726-0244
Tel: (559) 230-6000 FAX: (559) 230-6061
www.valleyair.org

Southern Region
2700 M Street, Suite 275
Bakersfield, CA 93301-2373
Tel: (661) 326-6900 FAX: (661) 326-6985

Per your request, the Authority to Construct will be issued with a Certificate of Conformity (COC). Your project will therefore go for EPA Review per District Rule 2520 for a 45-day period at the conclusion of our analysis, prior to the issuance of the final Authority to Construct permits.

We will begin processing your application as soon as possible. In general, complete applications are processed on a first-come first-served basis.

It is estimated that the project analysis process will take 171.2 hours, and you will be charged at the weighted hourly labor rate in accordance with District Rule 3010. This estimate includes the following major processing steps: Determining Completeness (21.2 hours), Engineering Evaluation (60 hours), BACT Analysis (30 hours), Health Risk Assessment (30 hours), CEQA Analysis (20 hours) and Permit Preparation (10 hours). The current weighted labor rate is $90.00 per hour, but please note that this fee is revised annually to reflect actual costs and therefore may change. No payment is due at this time; an invoice will be sent to you upon completion of this project.

Please note that this letter is not a permit and does not authorize you to proceed with your project. Final approval, if appropriate, will be in the form of ATC permits after application processing is complete. If you have any questions, please contact Mr. Rupi Gill at (209) 557-6400.

Sincerely,
David Warner
Director of Permit Services

Rupi Gill
Permit Services Manager
DW: jk

NCPA CT2
Received by: [illegible]
Date: 10.6.08

cc: Gerardo Rios, USEPA Reg. IX
75 Hawthorne St.
San Francisco, CA 94205

Tuan Ngo, California Energy Commission – MS 40
1516 9th Street
Sacramento, CA 95814

Jeff Adkins, Sierra Research
1801 J Street
Sacramento, CA 95814

ATTACHMENT DA5.1-2

Commissioning Activities Quantification and Duration

Table AQ-1
Detailed Emission Calculations for Turbine Commissioning
NCPA Lodi Energy Center

Commissioning Test	Activity	Days	Daily Operation (hrs/day)	GT Firing Rate (MMBtu/hr)	Pollutant	Emission Factor (lbs/MMBtu)	Hourly Emissions (lbs/hr)	Daily Emissions (lbs/day)	Total Emissions During Test (lbs)
FSNL + Ign. Tests	FSNL Operation	2	8	400	NOx		125	1,000.0	2,000.0
					CO		900	7,200.0	14,400.0
					VOC		16.00	128.0	256.0
					SOx	0.0028	1.12	9.0	17.9
					PM10		9.00	72.0	144.0
Steam Blows	Part Load Operation	3	10	1,220	NOx		400	4,000.0	12,000.0
					CO		2000	20,000.0	60,000.0
					VOC		16	160.0	480.0
					SOx	0.0028	3.42	34.2	102.5
					PM10		9.00	90.0	270.0
Part Load Tests	Part Load Operation	4	12	1,220	NOx	0.1088	132.71	1,592.5	6,369.9
					CO		385	4,620.0	18,480.0
					VOC		16.00	192.0	768.0
					SOx	0.00280	3 42	41 0	164.0
					PM10		9.00	108.0	432.0
Full Load Tests without SCR operational	Full Load Operation	4	12	1,885	NOx	0.0326	61.55	738.6	2,954.3
					CO	0.0066	12.46	149.5	598.1
					VOC	0.00180	3.33	40.0	159.8
					SOx	0.00280	5.37	64.4	257.8
					PM10		9.00	108.0	432.0
Multiple Load Tests with SCR at partial control	Startup/Shutdown	5	3	1,885	NOx		100.00	638.7	3,193.3
					CO		900.00	2812.1	14,060.7
					VOC		16.00	78.0	389.9
					SOx	0.0028	5.37	64.4	322.2
					PM10		9.00	108.0	540.0
	Full Load Operation		9		NOx	0.0200	37.63	inc	inc
					CO	0.0066	12.46	inc	inc
					VOC	0.0018	3.33	inc	inc
					SOx	0.0028	5.37	inc	inc
					PM10		9.00	inc	inc
Performance Tests with SCR at full control	Startup/Shutdown	10	3	1,885	NOx		100.00	437.3	4,372.5
					CO		900.00	2825.4	28,253.7
					VOC		16.00	95.9	958.8
					SOx	0.0028	5.37	70.1	701.1
					PM10		9.00	126.0	1,260.0
	Full Load Operation w/ Duct Firing		9	2,107.2	NOx	0.0072	15.25	inc	inc
					CO	0.0066	13.93	inc	inc
					VOC	0.0028	5.32	inc	inc
					SOx	0.0028	6.00	inc	inc
					PM10		11.00	inc	inc
Total Commissioning Hours:			292						

1. Emission factors during FSNL and ignition tests
   NOx - based on max expected hourly emission rate of 125 lbs/hr.
   CO - based on startup emission rate of 900 lbs/hr.
   VOC, SOx and PM10 - based on startup emission rates and 1.0 grain S/100 dscf n.g.
2. Emission factors during steam blows
   NOx - based on max expected hourly emission rate of 400 lbs/hr.
   CO - based on maximum expected hourly emission rate of 2000 lbs/hr.
   VOC, SOx and PM10 - based on startup emission rates and 1.0 grain S/100 dscf n.g.
3. Emission factors during part load tests
   NOx - based on estimate for part load test tuning combustor (ppm @ 15% O2) = 30
   CO - based on hourly emission rate used for Crockett Cogeneration plant commissioning period.
   VOC, SOx and PM10 - based on startup emission rates and 1.0 grain S/100 dscf n.g.
4. Emission factors during full load tests without SCR operational
   NOx level in ppmvd @ 15% O_2 = 9
   CO, VOC - based on combustor operating in pre-mix mode (3 ppmc CO and 1.4 ppmc for VOC).
   SOx and PM10 - emission factors based on fuel flow and 1.0 grain S/100 dscf n.g..
5. Emission factors during full load tests with SCR partially operational
   NOx - based information with combustor operating in pre-mix mode and SCR controlling NOx to 5.5 ppmc.
   CO, VOC - based on combustor operating in pre-mix mode (3 ppmc CO, 1.4 ppmc for VOC).
   SOx and PM10 - emission factors based on fuel flow and 1.0 grain S/100 dscf n.g..
6. Emission factors during full load tests with SCR fully operational
   NOx - based on combustor operating in pre-mix mode and SCR operational (2 ppmc NOx).
   CO, VOC - based on combustor operating in pre-mix mode and ox cat operational. 3 hours of startups (3 ppmc CO, 1.4/2.0 ppmc for VOC for 9 hours; 900 lb/hr for CO and 16 lb/hr for VOC during startups).
   SOx and PM10 - emission factors based on fuel flow and 1.0 grain S/100 dscf n.g..
7. Startup and shutdown emission rates unchanged.

Table AQ-2
Emissions During Commissioning
NCPA Lodi Energy Center

Unit	Maximum Hourly and Daily Emissions									
	Peak Hour Emissions					Peak Day Emissions				
	NOx	CO	VOC	SOx	PM10	NOx	CO	VOC	SOx	PM10
	(lbs/hr)					(lbs/day)				
One Gas Turbine in Steam Blow	400.0	2,000.0	16.0	6.0	11.0	4,000	20,000	192.0	70.1	126
Aux. Boiler	0.5	2.37	0.3	0.19	0.47	6.5	28.5	3.3	2.2	5.6
Total	400.5	2,002.4	16.3	6.2	11.5	4,007	20,028	195	72	132

Unit	Total Commissioning Emissions				
	NOx	CO	VOC	SOx	PM10
	(lbs)				
Gas Turbine/HRSG	30,890	135,792	2,853	1,565	3,078
Aux. Boiler (based on 60 hrs)	33	142	16	11	28
Total	30,923	135,935	2,869	1,577	3,106

N-2697
N-1083490

HAPs from
Cooling Towers
Biocides

NALCO 7330					
Gal Used	Max HR	0.0457	Max Yr	400	
Lbs per Gal		Specific Gravity		Lbs	
8.5				8.5	
Substance	Wt. %	Lbs/Hr	Lbs/Yr	Control (Y/N)	
Copper	2.00E-06	7.769E-09	0.000068		
		0	0		
		0	0		
		0	0		
		0	0		
		0	0		
		0	0		
		0	0		
		0	0		
		0	0		

Gal Used	Max HR	#DIV/0!	Max Yr	#DIV/0!	
Lbs per Gal					
				0	
Substance	Wt. %	Lbs/Hr	Lbs/Yr	Control (Y/N)	
		#DIV/0!	#DIV/0!		
		#DIV/0!	#DIV/0!		
		#DIV/0!	#DIV/0!		
		#DIV/0!	#DIV/0!		
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		#DIV/0!	#DIV/0!		
		#DIV/0!	#DIV/0!		

Gal Used	Max HR	#DIV/0!	Max Yr	#DIV/0!	
Lbs per Gal		Specific Gravity		Lbs	
				0	
Substance	Wt. %	Lbs/Hr	Lbs/Yr	Control (Y/N)	
		#DIV/0!	#DIV/0!		
		#DIV/0!	#DIV/0!		
		#DIV/0!	#DIV/0!		
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		#DIV/0!	#DIV/0!		
		#DIV/0!	#DIV/0!		

NALCO 3980					
Gal Used	**Max HR**	0.0063	**Max Yr**	55	
Lbs per Gal		**Specific Gravity**		**Lbs**	
8.5				8.5	
Substance	Wt. %	Lbs/Hr	Lbs/Yr	Control (Y/N)	
Copper	2.00E-06	1.071E-09	9.35E-06		
		0	0		
		0	0		
		0	0		
		0	0		
		0	0		
		0	0		
		0	0		
		0	0		
		0	0		

Gal Used	**Max HR**	#DIV/0!	**Max Yr**	#DIV/0!	
Lbs per Gal					
				0	
Substance	Wt. %	Lbs/Hr	Lbs/Yr	Control (Y/N)	
		#DIV/0!	#DIV/0!		
		#DIV/0!	#DIV/0!		
		#DIV/0!	#DIV/0!		
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		#DIV/0!	#DIV/0!		
		#DIV/0!	#DIV/0!		

Gal Used	**Max HR**	#DIV/0!	**Max Yr**	#DIV/0!	
Lbs per Gal		**Specific Gravity**		**Lbs**	
				0	
Substance	Wt. %	Lbs/Hr	Lbs/Yr	Control (Y/N)	
		#DIV/0!	#DIV/0!		
		#DIV/0!	#DIV/0!		
		#DIV/0!	#DIV/0!		
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		#DIV/0!	#DIV/0!		

Cheryl Lawler

From: Jagmeet Kahlon
Sent: Wednesday, October 22, 2008 4:50 PM
To: Cheryl Lawler
Subject: FW: question regarding biocide use at LEC
Attachments: Nalco_73551_UsCuEg.PDF; NALCO_7330_UsCuEg (3).pdf; 3980_MICROORGANISM_CONTROL_CHEMICAL_UsCuEg.PDF

Cheryl,

Here is the information that you requested on biocides for NCPA's project.
Cooling Towers

Thanks,
Jagmeet
ext. 6452

From: Nancy L. Matthews [mailto:NMatthews@sierraresearch.com]
Sent: Wednesday, October 22, 2008 10:02 AM
To: Jagmeet Kahlon
Cc: Nancy L. Matthews; Jeff Adkins
Subject: question regarding biocide use at LEC

Jag--

Attached are the MSDS sheets you requested. Annual usage of these substances is estimated as follows:

NALCO 3980 is 55 gallons
NALCO 73551 is 400 gallons
NALCO 7330 is 400 gallons

If you have any questions or require additional information regarding the project, please do not hesitate to call Jeff or me.

Nancy
Nancy Matthews
Sierra Research
1801 J Street
Sacramento, CA 95811

916-444-6666 (phone)
916-444-8373 (fax)

No HAPs

NALCO

MATERIAL SAFETY DATA SHEET

PRODUCT
Nalco 73551

EMERGENCY TELEPHONE NUMBER(S)
(800) 424-9300 (24 Hours) CHEMTREC

1. CHEMICAL PRODUCT AND COMPANY IDENTIFICATION

PRODUCT NAME : **Nalco 73551**

APPLICATION : DEPOSIT PENETRANT

COMPANY IDENTIFICATION : Nalco Company
1601 W. Diehl Road
Naperville, Illinois
60563-1198

EMERGENCY TELEPHONE NUMBER(S) : (800) 424-9300 (24 Hours) CHEMTREC

NFPA 704M/HMIS RATING
HEALTH : 0 / 1 FLAMMABILITY : 1 / 1 INSTABILITY : 0 / 0 OTHER :
0 = Insignificant 1 = Slight 2 = Moderate 3 = High 4 = Extreme

2. COMPOSITION/INFORMATION ON INGREDIENTS

Based on our hazard evaluation, none of the substances in this product are hazardous.

3. HAZARDS IDENTIFICATION

EMERGENCY OVERVIEW

CAUTION
May cause irritation with prolonged contact.
Do not get in eyes, on skin, on clothing. Do not take internally. Wear suitable protective clothing. Keep container tightly closed. Flush affected area with water.
May evolve oxides of carbon (COx) under fire conditions.

PRIMARY ROUTES OF EXPOSURE :
Eye, Skin

HUMAN HEALTH HAZARDS - ACUTE :

EYE CONTACT :
May cause irritation with prolonged contact.

SKIN CONTACT :
May cause irritation with prolonged contact.

INGESTION :
Not a likely route of exposure. No adverse effects expected.

INHALATION :
Not a likely route of exposure. No adverse effects expected.

SYMPTOMS OF EXPOSURE :
Acute :
A review of available data does not identify any symptoms from exposure not previously mentioned.
Chronic :
A review of available data does not identify any symptoms from exposure not previously mentioned.

AGGRAVATION OF EXISTING CONDITIONS :
A review of available data does not identify any worsening of existing conditions.

4. FIRST AID MEASURES

EYE CONTACT :
Flush affected area with water. If symptoms develop, seek medical advice.

SKIN CONTACT :
Flush affected area with water. If symptoms develop, seek medical advice.

INGESTION :
Do not induce vomiting without medical advice. If conscious, washout mouth and give water to drink. If symptoms develop, seek medical advice.

INHALATION :
Remove to fresh air, treat symptomatically. If symptoms develop, seek medical advice.

NOTE TO PHYSICIAN :
Based on the individual reactions of the patient, the physician's judgement should be used to control symptoms and clinical condition.

5. FIRE FIGHTING MEASURES

FLASH POINT : > 400 °F / > 200 °C (COC)

EXTINGUISHING MEDIA :
This product would not be expected to burn unless all the water is boiled away. The remaining organics may be ignitable. Use extinguishing media appropriate for surrounding fire.

FIRE AND EXPLOSION HAZARD :
May evolve oxides of carbon (COx) under fire conditions.

SPECIAL PROTECTIVE EQUIPMENT FOR FIRE FIGHTING :
In case of fire, wear a full face positive-pressure self contained breathing apparatus and protective suit.

6. ACCIDENTAL RELEASE MEASURES

PERSONAL PRECAUTIONS :
Do not touch spilled material. Restrict access to area as appropriate until clean-up operations are complete. Use personal protective equipment recommended in Section 8 (Exposure Controls/Personal Protection). Stop or reduce any leaks if it is safe to do so. Ventilate spill area if possible.

METHODS FOR CLEANING UP :
SMALL SPILLS: Soak up spill with absorbent material. Place residues in a suitable, covered, properly labeled container. Wash affected area. LARGE SPILLS: Contain liquid using absorbent material, by digging trenches or by diking. Reclaim into recovery or salvage drums or tank truck for proper disposal. Contact an approved waste hauler for disposal of contaminated recovered material. Dispose of material in compliance with regulations indicated in Section 13 (Disposal Considerations).

ENVIRONMENTAL PRECAUTIONS :
Do not contaminate surface water.

7. HANDLING AND STORAGE

HANDLING :
Avoid eye and skin contact. Do not take internally. Ensure all containers are labelled. Keep the containers closed when not in use.

STORAGE CONDITIONS :
Store the containers tightly closed.

8. EXPOSURE CONTROLS/PERSONAL PROTECTION

OCCUPATIONAL EXPOSURE LIMITS :
This product does not contain any substance that has an established exposure limit.

ENGINEERING MEASURES :
General ventilation is recommended.

RESPIRATORY PROTECTION :
Respiratory protection is not normally needed.

HAND PROTECTION :
Neoprene gloves, Nitrile gloves, Butyl gloves, PVC gloves

SKIN PROTECTION :
Wear standard protective clothing.

EYE PROTECTION :
Wear chemical splash goggles.

HYGIENE RECOMMENDATIONS :
Keep an eye wash fountain available. Keep a safety shower available. If clothing is contaminated, remove clothing and thoroughly wash the affected area. Launder contaminated clothing before reuse.

9. PHYSICAL AND CHEMICAL PROPERTIES

PHYSICAL STATE Liquid

APPEARANCE	Clear Colorless
ODOR	None
SPECIFIC GRAVITY	0.99 - 1.03 @ 77 °F / 25 °C
SOLUBILITY IN WATER	Complete
pH (100 %)	6.6 - 7.0

Note: These physical properties are typical values for this product and are subject to change.

10. STABILITY AND REACTIVITY

STABILITY :
Stable under normal conditions.

HAZARDOUS POLYMERIZATION :
Hazardous polymerization will not occur.

CONDITIONS TO AVOID :
Freezing temperatures.

MATERIALS TO AVOID :
None known

HAZARDOUS DECOMPOSITION PRODUCTS :
Under fire conditions: Oxides of carbon

11. TOXICOLOGICAL INFORMATION

The following results are for the polymer.

ACUTE ORAL TOXICITY :

Species	LD50	Test Descriptor
Rat	2,300 - 16,000 mg/kg	The following results are for the polymer.

Rating : Non-Hazardous

CARCINOGENICITY :
None of the substances in this product are listed as carcinogens by the International Agency for Research on Cancer (IARC), the National Toxicology Program (NTP) or the American Conference of Governmental Industrial Hygienists (ACGIH).

HUMAN HAZARD CHARACTERIZATION :
Based on our hazard characterization, the potential human hazard is: Low

12. ECOLOGICAL INFORMATION

ECOTOXICOLOGICAL EFFECTS :

The following results are for the product.

ACUTE FISH RESULTS :

Species	Exposure	LC50	Test Descriptor
Rainbow Trout	96 hrs	> 1,000 mg/l	Product
Bluegill Sunfish	96 hrs	> 1,000 mg/l	Product
Fathead Minnow	96 hrs	996 mg/l	Product

ACUTE INVERTEBRATE RESULTS :

Species	Exposure	LC50	EC50	Test Descriptor
Daphnia magna	48 hrs		> 1,000 mg/l	Product
Ceriodaphnia dubia	48 hrs	1,320 mg/l		Product

CHRONIC FISH RESULTS :

Species	Exposure	NOEC / LOEC	End Point	Test Descriptor
Fathead Minnow	7 Days	250 mg/l / 500 mg/l	Reproduction	Product

CHRONIC INVERTEBRATE RESULTS :

Species	Test Type	NOEC / LOEC	End Point	Test Descriptor
Ceriodaphnia dubia	3 Brood	125 mg/l / 250 mg/l	Reproduction	Product

PERSISTENCY AND DEGRADATION :

Total Organic Carbon (TOC) : 85,000 mg/l

Chemical Oxygen Demand (COD) : 250,000 mg/l

Biological Oxygen Demand (BOD) :

Incubation Period	Value	Test Descriptor
5 d	4 mg/l	Product

ENVIRONMENTAL HAZARD AND EXPOSURE CHARACTERIZATION
Based on our hazard characterization, the potential environmental hazard is: Low

If released into the environment, see CERCLA/SUPERFUND in Section 15.

13. DISPOSAL CONSIDERATIONS

If this product becomes a waste, it is not a hazardous waste as defined by the Resource Conservation and Recovery Act (RCRA) 40 CFR 261, since it does not have the characteristics of Subpart C, nor is it listed under Subpart D.

As a non-hazardous waste, it is not subject to federal regulation. Consult state or local regulation for any additional handling, treatment or disposal requirements. For disposal, contact a properly licensed waste treatment, storage, disposal or recycling facility.

14. TRANSPORT INFORMATION

The information in this section is for reference only and should not take the place of a shipping paper (bill of lading) specific to an order. Please note that the proper Shipping Name / Hazard Class may vary by packaging, properties, and mode of transportation. Typical Proper Shipping Names for this product are as follows.

LAND TRANSPORT :

Proper Shipping Name : PRODUCT IS NOT REGULATED DURING TRANSPORTATION

AIR TRANSPORT (ICAO/IATA) :

Proper Shipping Name : PRODUCT IS NOT REGULATED DURING TRANSPORTATION

MARINE TRANSPORT (IMDG/IMO) :

Proper Shipping Name : PRODUCT IS NOT REGULATED DURING TRANSPORTATION

15. REGULATORY INFORMATION

NATIONAL REGULATIONS, USA :

OSHA HAZARD COMMUNICATION RULE, 29 CFR 1910.1200 :
Based on our hazard evaluation, none of the substances in this product are hazardous.

CERCLA/SUPERFUND, 40 CFR 117, 302 :
Notification of spills of this product is not required.

SARA/SUPERFUND AMENDMENTS AND REAUTHORIZATION ACT OF 1986 (TITLE III) - SECTIONS 302, 311, 312, AND 313 :

SECTION 302 - EXTREMELY HAZARDOUS SUBSTANCES (40 CFR 355) :
This product does not contain substances listed in Appendix A and B as an Extremely Hazardous Substance.

SECTIONS 311 AND 312 - MATERIAL SAFETY DATA SHEET REQUIREMENTS (40 CFR 370) :
Our hazard evaluation has found that this product is not hazardous under 29 CFR 1910.1200.

Under SARA 311 and 312, the EPA has established threshold quantities for the reporting of hazardous chemicals. The current thresholds are: 500 pounds or the threshold planning quantity (TPQ), whichever is lower, for extremely hazardous substances and 10,000 pounds for all other hazardous chemicals.

SECTION 313 - LIST OF TOXIC CHEMICALS (40 CFR 372) :
This product does not contain substances on the List of Toxic Chemicals.

TOXIC SUBSTANCES CONTROL ACT (TSCA) :
The substances in this preparation are included on or exempted from the TSCA 8(b) Inventory (40 CFR 710)

FOOD AND DRUG ADMINISTRATION (FDA) Federal Food, Drug and Cosmetic Act :
When use situations necessitate compliance with FDA regulations, this product is acceptable under : 21 CFR 173.340 Defoaming Agents, 21 CFR 175.105 Adhesives, 21 CFR 176.200 Defoaming Agents used in coatings, 21 CFR 176.210 Defoaming agents used in the manufacture of paper and paperboard, 21 CFR 177.1200 Cellophane, 21 CFR 177.1400 Hydroxyethyl cellulose film, water-insoluble, 21 CFR 176.300 Slimicides, 21 CFR 178.3120 - Animal glue

Limitations: no more than required to produce intended technical effect.

NSF NON-FOOD COMPOUNDS REGISTRATION PROGRAM (former USDA List of Proprietary Substances & Non-Food Compounds) :
NSF Registration number for this product is : 137540
This product is acceptable for treatment of cooling and retort water (G5) in and around food processing areas.

This product has been certified as KOSHER/PAREVE for year-round use INCLUDING THE PASSOVER SEASON by the CHICAGO RABBINICAL COUNCIL.

FEDERAL WATER POLLUTION CONTROL ACT, CLEAN WATER ACT, 40 CFR 401.15 / formerly Sec. 307, 40 CFR 116.4 / formerly Sec. 311 :
None of the substances are specifically listed in the regulation.

CLEAN AIR ACT, Sec. 112 (40 CFR 61, Hazardous Air Pollutants), Sec. 602 (40 CFR 82, Class I and II Ozone Depleting Substances) :
None of the substances are specifically listed in the regulation.

CALIFORNIA PROPOSITION 65 :
This product does not contain substances which require warning under California Proposition 65.

MICHIGAN CRITICAL MATERIALS :
None of the substances are specifically listed in the regulation.

STATE RIGHT TO KNOW LAWS :
The following substances are disclosed for compliance with State Right to Know Laws:

Water	7732-18-5
Polyalkylene glycol	Proprietary

NATIONAL REGULATIONS, CANADA :

WORKPLACE HAZARDOUS MATERIALS INFORMATION SYSTEM (WHMIS) :
This product has been classified in accordance with the hazard criteria of the Controlled Products Regulations (CPR) and the MSDS contains all the information required by the CPR.

WHMIS CLASSIFICATION :
Not considered a WHMIS controlled product.

CANADIAN ENVIRONMENTAL PROTECTION ACT (CEPA) :
The substances in this preparation are listed on the Domestic Substances List (DSL), are exempt, or have been reported in accordance with the New Substances Notification Regulations.

16. OTHER INFORMATION

Due to our commitment to Product Stewardship, we have evaluated the human and environmental hazards and exposures of this product. Based on our recommended use of this product, we have characterized the product's general risk. This information should provide assistance for your own risk management practices. We have evaluated our product's risk as follows:

* The human risk is: Low

* The environmental risk is: Low

Any use inconsistent with our recommendations may affect the risk characterization. Our sales representative will assist you to determine if your product application is consistent with our recommendations. Together we can implement an appropriate risk management process.

This product material safety data sheet provides health and safety information. The product is to be used in applications consistent with our product literature. Individuals handling this product should be informed of the recommended safety precautions and should have access to this information. For any other uses, exposures should be evaluated so that appropriate handling practices and training programs can be established to insure safe workplace operations. Please consult your local sales representative for any further information.

REFERENCES

Threshold Limit Values for Chemical Substances and Physical Agents and Biological Exposure Indices, American Conference of Governmental Industrial Hygienists, OH., (Ariel Insight# CD-ROM Version), Ariel Research Corp., Bethesda, MD.

Hazardous Substances Data Bank, National Library of Medicine, Bethesda, Maryland (TOMES CPS# CD-ROM Version), Micromedex, Inc., Englewood, CO.

IARC Monographs on the Evaluation of the Carcinogenic Risk of Chemicals to Man, Geneva: World Health Organization, International Agency for Research on Cancer.

Integrated Risk Information System, U.S. Environmental Protection Agency, Washington, D.C. (TOMES CPS# CD-ROM Version), Micromedex, Inc., Englewood, CO.

Annual Report on Carcinogens, National Toxicology Program, U.S. Department of Health and Human Services, Public Health Service.

Title 29 Code of Federal Regulations, Part 1910, Subpart Z, Toxic and Hazardous Substances, Occupational Safety and Health Administration (OSHA), (Ariel Insight# CD-ROM Version), Ariel Research Corp., Bethesda, MD.

Registry of Toxic Effects of Chemical Substances, National Institute for Occupational Safety and Health, Cincinnati, OH, (TOMES CPS# CD-ROM Version), Micromedex, Inc., Englewood, CO.

Ariel Insight# (An integrated guide to industrial chemicals covered under major regulatory and advisory programs), North American Module, Western European Module, Chemical Inventories Module and the Generics Module (Ariel Insight# CD-ROM Version), Ariel Research Corp., Bethesda, MD.

The Teratogen Information System, University of Washington, Seattle, WA (TOMES CPS# CD-ROM Version), Micromedex, Inc., Englewood, CO.

Prepared By : Product Safety Department
Date issued : 05/08/2006
Version Number : 1.12

NALCO

MATERIAL SAFETY DATA SHEET

PRODUCT

NALCO 7330

EMERGENCY TELEPHONE NUMBER(S)
(800) 424-9300 (24 Hours) CHEMTREC

1. CHEMICAL PRODUCT AND COMPANY IDENTIFICATION

PRODUCT NAME : **NALCO 7330**

COMPANY IDENTIFICATION : Nalco Company
1601 W. Diehl Road
Naperville, Illinois
60563-1198

EMERGENCY TELEPHONE NUMBER(S) : (800) 424-9300 (24 Hours) CHEMTREC

NFPA 704M/HMIS RATING
HEALTH : 3 / 3 FLAMMABILITY : 0 / 0 INSTABILITY : 0 / 0 OTHER :
0 = Insignificant 1 = Slight 2 = Moderate 3 = High 4 = Extreme

2. COMPOSITION/INFORMATION ON INGREDIENTS

Our hazard evaluation has identified the following chemical substance(s) as hazardous. Consult Section 15 for the nature of the hazard(s).

Hazardous Substance(s)	CAS NO	% (w/w)
5-Chloro-2-Methyl-4-Isothiazolin-3-one	26172-55-4	1 - 5
2-Methyl-4-Isothiazolin-3-one	2682-20-4	0.1 - 1
Magnesium Nitrate	10377-60-3	1 - 5

3. HAZARDS IDENTIFICATION

EMERGENCY OVERVIEW

DANGER

CORROSIVE. CAUSES IRREVERSIBLE EYE DAMAGE OR SKIN BURNS. HARMFUL IF INHALED, SWALLOWED OR ABSORBED THROUGH SKIN. Do not get in eyes, on skin or on clothing. Prolonged or frequently repeated skin contact may cause allergic reaction in some individuals.
Mixers, loaders, and others exposed to this product must wear: long-sleeved shirt and long pants; chemical resistant gloves such as nitrile or butyl rubber; shoes plus socks; goggles and face shield; and chemical resistant apron. Discard clothing or other absorbent materials that have been drenched or heavily contaminated with this product's concentrate. Do not reuse them. Follow manufacturer's instructions for cleaning/maintaining PPE. If no such instructions for washables exist, use detergent and hot water. Keep and wash PPE separately from other laundry. Users should wash hands before eating, drinking, chewing gum, using tobacco or using the toilet. Users should remove clothing immediately if pesticide gets inside. Then wash thoroughly and put on clean clothing. Users should remove PPE immediately after handling the product. Wash the outside of gloves before removing. As soon as possible, wash thoroughly. Do not apply this product in a way that will contact workers or other persons. May evolve oxides of carbon (COx) under fire conditions. May evolve HCl under fire conditions. May evolve oxides of nitrogen (NOx) and sulfur (SOx) under fire conditions. Not flammable or combustible.

PRIMARY ROUTES OF EXPOSURE :
Eye, Skin

HUMAN HEALTH HAZARDS - ACUTE :

EYE CONTACT :
Corrosive. Will cause eye burns and permanent tissue damage.

SKIN CONTACT :
May cause severe irritation or tissue damage depending on the length of exposure and the type of first aid administered. Repeated or prolonged contact may cause skin sensitization.

INGESTION :
Not a likely route of exposure. Corrosive; causes chemical burns to the mouth, throat and stomach.

INHALATION :
Not a likely route of exposure. Irritating, in high concentrations, to the eyes, nose, throat and lungs.

SYMPTOMS OF EXPOSURE :
Acute :
A review of available data does not identify any symptoms from exposure not previously mentioned.
Chronic :
A review of available data does not identify any symptoms from exposure not previously mentioned.

AGGRAVATION OF EXISTING CONDITIONS :
A review of available data does not identify any worsening of existing conditions.

4. FIRST AID MEASURES

IF IN EYES: Hold eyes open and rinse slowly and gently with water for 15-20 minutes. Remove contact lenses, if present, after the first 5 minutes, then continue rinsing. Call a poison control center or doctor for treatment advice.

IF SWALLOWED: Call a poison control center or doctor immediately for treatment advice. Have person sip a glass of water if able to swallow. Do not induce vomiting unless told by a poison control center or doctor.

IF ON SKIN: Take off contaminated clothing. Rinse skin immediately with plenty of water for 15-20 minutes. Call a poison control center or doctor for treatment advice.

IF INHALED: Move person to fresh air. If person is not breathing, call 911 or ambulances, then give artificial respiration, preferably mouth-to-mouth, if possible. Call a poison control center or doctor for treatment advice

NOTE TO PHYSICIAN :
Probable mucosal damage may contraindicate the use of gastric lavage. Based on the individual reactions of the patient, the physician's judgement should be used to control symptoms and clinical condition.

5. FIRE FIGHTING MEASURES

FLASH POINT : None

EXTINGUISHING MEDIA :
Not expected to burn. Use extinguishing media appropriate for surrounding fire.

FIRE AND EXPLOSION HAZARD :
May evolve oxides of carbon (COx) under fire conditions. May evolve HCl under fire conditions. May evolve oxides of nitrogen (NOx) and sulfur (SOx) under fire conditions. Not flammable or combustible.

SPECIAL PROTECTIVE EQUIPMENT FOR FIRE FIGHTING :
In case of fire, wear a full face positive-pressure self contained breathing apparatus and protective suit.

6. ACCIDENTAL RELEASE MEASURES

PERSONAL PRECAUTIONS :
Restrict access to area as appropriate until clean-up operations are complete. Ensure clean-up is conducted by trained personnel only. Ventilate spill area if possible. Do not touch spilled material. Stop or reduce any leaks if it is safe to do so. Use personal protective equipment recommended in Section 8 (Exposure Controls/Personal Protection). Notify appropriate government, occupational health and safety and environmental authorities.

METHODS FOR CLEANING UP :
SMALL SPILLS: Soak up spill with absorbent material. Place residues in a suitable, covered, properly labeled container. Wash affected area. LARGE SPILLS: Soak up with inert absorbent material. Transfer contaminated material to suitable containers for disposal. Contaminated surfaces should be swabbed with deactivation solution, let stand for 30 minutes and rinse thoroughly with clean water. DO NOT add deactivation solution to the waste container to deactivate the absorbed material. *DEACTIVATION SOLUTION - prepare fresh a solution of 5% Sodium bicarbonate and 5% Sodium hypochlorite in water. Use a ratio of 10 volumes decontamination solution per estimated volume of residual spill. Wash site of spillage thoroughly with water. Contact an approved waste hauler for disposal of contaminated recovered material. Dispose of material in compliance with regulations indicated in Section 13 (Disposal Considerations).

ENVIRONMENTAL PRECAUTIONS :
This pesticide is toxic to fish and wildlife. Do not discharge effluent containing this product into lakes, streams, ponds, estuaries, oceans or other waters, unless in accordance with the requirements of a National Pollutant Discharge Elimination System (NPDES) permit and the permitting authority has been notified in writing prior to discharge. Do not discharge effluent containing this product to sewer systems without previously notifying the local sewage treatment plant authority. For guidance contact your State Water Board or Regional Office of the EPA. Do not contaminate water by cleaning of equipment or disposal of waste. Apply this pesticide only as specified on this label.

7. HANDLING AND STORAGE

HANDLING :
Do not get in eyes, on skin, on clothing. Do not take internally. Use with adequate ventilation. Avoid generating aerosols and mists. Keep the containers closed when not in use. Have emergency equipment (for fires, spills, leaks, etc.) readily available.

STORAGE CONDITIONS :
Store the containers tightly closed. Store separately from oxidizers. Store in suitable labelled containers.

SUITABLE CONSTRUCTION MATERIAL :
Stainless Steel 316L, Polyethylene, Polypropylene, Viton

UNSUITABLE CONSTRUCTION MATERIAL :
Steel

8. EXPOSURE CONTROLS/PERSONAL PROTECTION

OCCUPATIONAL EXPOSURE LIMITS :
This product contains the following component(s) with a recognised or recommended OEL value:
Manufacturer's Recommendation :

Substance(s)	
5-Chloro-2-Methyl-4-Isothiazolin-3-one	TWA: 0.076 mg/m3 STEL: 0.23 mg/m3

Manufacturer's Recommendation :

Substance(s)	
2-Methyl-4-Isothiazolin-3-one	TWA: 1.5 mg/m3 STEL: 4.5 mg/m3

ENGINEERING MEASURES :
General ventilation is recommended. Use local exhaust ventilation if necessary to control airborne mist and vapor.

RESPIRATORY PROTECTION :
If significant mists, vapors or aerosols are generated an approved respirator is recommended. A suitable filter material depends on the amount and type of chemicals being handled. Consider the use of filter type: Particulate filter - HEPA. In event of emergency or planned entry into unknown concentrations a positive pressure, full-facepiece SCBA should be used. If respiratory protection is required, institute a complete respiratory protection program including selection, fit testing, training, maintenance and inspection.

HAND PROTECTION :
PVC gloves

SKIN PROTECTION :
Wear chemical resistant apron, chemical splash goggles, impervious gloves and boots. A full slicker suit is recommended if gross exposure is possible.

EYE PROTECTION :
Wear a face shield with chemical splash goggles.

HYGIENE RECOMMENDATIONS :
Eye wash station and safety shower are necessary. If clothing is contaminated, remove clothing and thoroughly wash the affected area. Launder contaminated clothing before reuse.

HUMAN EXPOSURE CHARACTERIZATION :
Based on our recommended product application and personal protective equipment, the potential human exposure is: Moderate

9. PHYSICAL AND CHEMICAL PROPERTIES

PHYSICAL STATE	Liquid
APPEARANCE	Light green Light yellow
ODOR	Mild
SPECIFIC GRAVITY	1.026
DENSITY	8.5 lb/gal
SOLUBILITY IN WATER	Complete
pH (100 %)	3.0 - 5.0
FREEZING POINT	25 °F / -4 °C
BOILING POINT	/ 100 °C
VOC CONTENT	0.80 % EPA Method 24

Note: These physical properties are typical values for this product and are subject to change.

10. STABILITY AND REACTIVITY

STABILITY :
Stable under normal conditions.

HAZARDOUS POLYMERIZATION :
Hazardous polymerization will not occur.

CONDITIONS TO AVOID :
Freezing temperatures.

MATERIALS TO AVOID :
Contact with strong oxidizers (e.g. chlorine, peroxides, chromates, nitric acid, perchlorate, concentrated oxygen, permanganate) may generate heat, fires, explosions and/or toxic vapors.

HAZARDOUS DECOMPOSITION PRODUCTS :
Under fire conditions: Oxides of carbon, Oxides of nitrogen, Oxides of sulfur, HCl

11. TOXICOLOGICAL INFORMATION

The following results are for the product along with results on the active substances.

ACUTE ORAL TOXICITY :

Species	LD50	Test Descriptor
Rat	3,810 mg/kg	Product

Rating : Non-Hazardous

ACUTE DERMAL TOXICITY :

Species	LD50	Test Descriptor
Rabbit	> 5,000 mg/kg	Product

Rating : Non-Hazardous

ACUTE INHALATION TOXICITY :

Species	LC50	Test Descriptor
Rat	13.7 mg/l (4 hrs)	Product

Rating : Toxic

PRIMARY SKIN IRRITATION : A 1.5% active solution is corrosive to skin, a 0.6% active solution is a severe skin irritant, a 0.3% active solution is a moderate skin irritant and a 0.06% active solution is a non-irritant.

PRIMARY EYE IRRITATION : A 1.5% active solution is corrosive to the eyes, a 0.3% active solution is an eye irritant and 0.06% active solution is a non-irritant.

SENSITIZATION :
Repeated or prolonged contact may cause sensitization in some individuals. A Guinea pig (Buehler Technique) sensitization study with an induction dosage of 90 ppm of active ingredients followed by an insult of 429 ppm of active ingredients was positive. A human repeated insult patch study of 28 ppm active ingredients followed by an insult of 56 ppm of active ingredients resulted in no effect to the subjects tested.

CHRONIC TOXICITY DATA :
A 90-day dietary study in dogs of 840 ppm of isothiazolinone resulted in no mortalities or pathological findings. A 90-day dermal study in rabbits of 0.4 mg/kg/day of isothiazolinone resulted in irritation but no pathological effects. A 30-month skin painting study with mice using 400 ppm isothiazolinone three times per week showed no increased tumor frequency over control. A teratology study with rabbits and rats was negative using dosages of 1.5 to 15 mg/kg isothiazolinone. Mutagenicity results have been equivocal.

CARCINOGENICITY :
None of the substances in this product are listed as carcinogens by the International Agency for Research on Cancer (IARC), the National Toxicology Program (NTP) or the American Conference of Governmental Industrial Hygienists (ACGIH).

HUMAN HAZARD CHARACTERIZATION :
Based on our hazard characterization, the potential human hazard is: High

12. ECOLOGICAL INFORMATION

ECOTOXICOLOGICAL EFFECTS :

The following results are for the product along with results on the active substances.

ACUTE FISH RESULTS :

Species	Exposure	LC50	Test Descriptor
Sheepshead Minnow	96.00 hrs	32.000 mg/l	Product
Bluegill Sunfish	96 hrs	18.67 mg/l	Product
Fathead Minnow	144 hrs	8 mg/l	Product
Rainbow Trout	96 hrs	12.67 mg/l	Product
Inland Silverside	96 hrs	16.62 mg/l	Product

ACUTE INVERTEBRATE RESULTS :

Species	Exposure	LC50	EC50	Test Descriptor
Mysid Shrimp (Mysidopsis bahia)	96.00 hrs	18.000 mg/l		Product
Ceriodaphnia dubia	48 hrs	15 mg/l		Product
Daphnia magna	48 hrs	8.7 - 12 mg/l		Product
Blue Mussel	48 hrs	865 mg/l		Product
American Oyster	48 hrs	1,730 mg/l		Product

AVIAN RESULTS :

Species	Exposure	LC50	Test Descriptor
Bobwhite Quail	8 Days	> 60 mg/kg > 560 ppm	

PERSISTENCY AND DEGRADATION :

Total Organic Carbon (TOC) : 7,850 mg/l

Chemical Oxygen Demand (COD) : 20,000 mg/l

The degradation of the major active substance begins with ring opening and elimination of chloride ion. Degradation leads to the formation of a variety of small organic acids, methylamine, carbon dioxide and elemental sulfur. The half life of each active substance is dependent upon the initial concentration.

MOBILITY :
The environmental fate was estimated using a level III fugacity model embedded in the EPI (estimation program interface) Suite TM , provided by the US EPA. The model assumes a steady state condition between the total input and output. The level III model does not require equilibrium between the defined media. The information provided is intended to give the user a general estimate of the environmental fate of this product under the defined conditions of the models. If released into the environment this material is expected to distribute to the air, water and soil/sediment in the approximate respective percentages;

Air	Water	Soil/Sediment
<5%	30 - 50%	50 - 70%

The portion in water is expected to be soluble or dispersible.

BIOACCUMULATION POTENTIAL
This preparation or material is not expected to bioaccumulate.

ENVIRONMENTAL HAZARD AND EXPOSURE CHARACTERIZATION
Based on our hazard characterization, the potential environmental hazard is: Moderate
Based on our recommended product application and the product's characteristics, the potential environmental exposure is: Moderate

If released into the environment, see CERCLA/SUPERFUND in Section 15.

13. DISPOSAL CONSIDERATIONS

If this product becomes a waste, it could meet the criteria of a hazardous waste as defined by the Resource Conservation and Recovery Act (RCRA) 40 CFR 261. Before disposal, it should be determined if the waste meets the criteria of a hazardous waste.

Pesticide wastes are toxic. Improper disposal of excess pesticide, spray mixture, or rinsate is a violation of Federal law. If these wastes cannot be disposed of by use according to label instructions, contact your State Pesticide or Environmental Control Agency, or the Hazardous Waste Representative at the nearest EPA Regional Office for guidance.

Metal Containers: Triple rinse (or equivalent). Then offer for recycling or reconditioning, or puncture and dispose of in a sanitary landfill, or other procedures approved by state and local authorities. Plastic Containers: ^PLASTIC CONTAINERS: Do not reuse empty container. Triple rinse (or equivalent). Then puncture and dispose of in a sanitary landfill, or, if allowed by state and local authorities, by burning. If burned, stay out of smoke.

14. TRANSPORT INFORMATION

The information in this section is for reference only and should not take the place of a shipping paper (bill of lading) specific to an order. Please note that the proper Shipping Name / Hazard Class may vary by packaging, properties, and mode of transportation. Typical Proper Shipping Names for this product are as follows.

LAND TRANSPORT :

Proper Shipping Name :	CORROSIVE LIQUID, ACIDIC, ORGANIC, N.O.S.
Technical Name(s) :	ISOTHIAZOLINONE MICROBIOCIDE
UN/ID No :	UN 3265
Hazard Class - Primary :	8
Packing Group :	II
Flash Point :	None

AIR TRANSPORT (ICAO/IATA) :

Proper Shipping Name :	CORROSIVE LIQUID, ACIDIC, ORGANIC, N.O.S.
Technical Name(s) :	ISOTHIAZOLINONE MICROBIOCIDE
UN/ID No :	UN 3265
Hazard Class - Primary :	8
Packing Group :	II
IATA Cargo Packing Instructions :	812
IATA Cargo Aircraft Limit :	30 L (Max net quantity per package)

MARINE TRANSPORT (IMDG/IMO) :

Proper Shipping Name :	CORROSIVE LIQUID, ACIDIC, ORGANIC, N.O.S.
Technical Name(s) :	ISOTHIAZOLINONE MICROBIOCIDE
UN/ID No :	UN 3265
Hazard Class - Primary :	8

Packing Group : II

15. REGULATORY INFORMATION

NATIONAL REGULATIONS, USA :

OSHA HAZARD COMMUNICATION RULE, 29 CFR 1910.1200 :
Based on our hazard evaluation, the following substance(s) in this product is/are hazardous and the reason(s) is/are shown below.

5-Chloro-2-Methyl-4-Isothiazolin-3-one : Corrosive, Sensitizer
2-Methyl-4-Isothiazolin-3-one : Corrosive, Sensitizer
Magnesium Nitrate : Eye irritant

CERCLA/SUPERFUND, 40 CFR 117, 302 :
Notification of spills of this product is not required.

SARA/SUPERFUND AMENDMENTS AND REAUTHORIZATION ACT OF 1986 (TITLE III) - SECTIONS 302, 311, 312, AND 313 :

SECTION 302 - EXTREMELY HAZARDOUS SUBSTANCES (40 CFR 355) :
This product does not contain substances listed in Appendix A and B as an Extremely Hazardous Substance.

SECTIONS 311 AND 312 - MATERIAL SAFETY DATA SHEET REQUIREMENTS (40 CFR 370) :
Our hazard evaluation has found this product to be hazardous. The product should be reported under the following indicated EPA hazard categories:

X	Immediate (Acute) Health Hazard
X	Delayed (Chronic) Health Hazard
-	Fire Hazard
-	Sudden Release of Pressure Hazard
-	Reactive Hazard

Under SARA 311 and 312, the EPA has established threshold quantities for the reporting of hazardous chemicals. The current thresholds are: 500 pounds or the threshold planning quantity (TPQ), whichever is lower, for extremely hazardous substances and 10,000 pounds for all other hazardous chemicals.

SECTION 313 - LIST OF TOXIC CHEMICALS (40 CFR 372) :
This product contains the following substance(s), (with CAS # and % range) which appear(s) on the List of Toxic Chemicals

Hazardous Substance(s)	CAS NO	% (w/w)
Magnesium Nitrate	10377-60-3	1.0 - 5.0

TOXIC SUBSTANCES CONTROL ACT (TSCA) :
This product is exempted under TSCA and regulated under FIFRA. The inerts are on the Inventory List.

FOOD AND DRUG ADMINISTRATION (FDA) Federal Food, Drug and Cosmetic Act :
When use situations necessitate compliance with FDA regulations, this product is acceptable under : 21 CFR 176.300 Slimicides 21 CFR 176.170 Components of paper and paperboard in contact with aqueous and fatty foods and 21 CFR 176.180 Components of paper and paperboard in contact with dry foods. 21 CFR 176.170 Components of paper and paperboard in contact with aqueous and fatty foods and 21 CFR 176.180 Components of paper and paperboard in contact with dry foods.

The following limitations apply:

Maximum dosage	Limitation
FOR 176.300: 0.125% (ACTIVES)	of dry weight fiber
FOR 176.170/180: 1675 PPM	as an antimicrobial agent for finished coating formulations and for additives used in the manufacture of paper and paperboard, including fillers, binders, pigment sluries and sizing solutions
FOR 176.170/180: 3350 PPM	as an antimicrobial agent for polymer latex emulsions in paper coatings

NSF NON-FOOD COMPOUNDS REGISTRATION PROGRAM (former USDA List of Proprietary Substances & Non-Food Compounds) :
NSF Registration number for this product is : 062419
This product is acceptable for treating boilers, steam lines, and/or cooling systems (G7) where neither the treated water nor the steam produced may contact edible products in and around food processing areas.

FEDERAL INSECTICIDE, FUNGICIDE AND RODENTICIDE ACT (FIFRA) :
EPA Reg. No. 1706-153
In all cases follow instructions on the product label.

This product has been certified as KOSHER/PAREVE for year-round use INCLUDING THE PASSOVER SEASON by the CHICAGO RABBINICAL COUNCIL.

FEDERAL WATER POLLUTION CONTROL ACT, CLEAN WATER ACT, 40 CFR 401.15 / formerly Sec. 307, 40 CFR 116.4 / formerly Sec. 311 :
This product contains the following substances listed in the regulation:

Substance(s)	Citations
• Cupric Nitrate	Sec. 307, Sec. 311

CLEAN AIR ACT, Sec. 112 (40 CFR 61, Hazardous Air Pollutants), Sec. 602 (40 CFR 82, Class I and II Ozone Depleting Substances) :
None of the substances are specifically listed in the regulation.

CALIFORNIA PROPOSITION 65 :
This product does not contain substances which require warning under California Proposition 65.

MICHIGAN CRITICAL MATERIALS :
This product contains the following substances listed in the regulation:

Copper

STATE RIGHT TO KNOW LAWS :
The following substances are disclosed for compliance with State Right to Know Laws:

Copper	7440-50-8
Magnesium Nitrate	10377-60-3

NATIONAL REGULATIONS, CANADA :

WORKPLACE HAZARDOUS MATERIALS INFORMATION SYSTEM (WHMIS) :
This product has been classified in accordance with the hazard criteria of the Controlled Products Regulations (CPR) and the MSDS contains all the information required by the CPR.

WHMIS CLASSIFICATION :
Pesticide controlled products are not regulated under WHMIS.

CANADIAN ENVIRONMENTAL PROTECTION ACT (CEPA) :
The substances in this preparation are listed on the Domestic Substances List (DSL), are exempt, or have been reported in accordance with the New Substances Notification Regulations.

INTERNATIONAL CHEMICAL CONTROL LAWS

AUSTRALIA
All substances in this product comply with the National Industrial Chemicals Notification & Assessment Scheme (NICNAS).

EUROPE
The substances in this preparation have been reviewed for compliance with the EINECS or ELINCS inventories.

JAPAN
All substances in this product comply with the Law Regulating the Manufacture and Importation Of Chemical Substances and are listed on the Ministry of International Trade & industry List (MITI).

KOREA
All substances in this product comply with the Toxic Chemical Control Law (TCCL) and are listed on the Existing Chemicals List (ECL)

THE PHILIPPINES
All substances in this product comply with the Republic Act 6969 (RA 6969) and are listed on the Philippine Inventory of Chemicals & Chemical Substances (PICCS).

16. OTHER INFORMATION

Due to our commitment to Product Stewardship, we have evaluated the human and environmental hazards and exposures of this product. Based on our recommended use of this product, we have characterized the product's general risk. This information should provide assistance for your own risk management practices. We have evaluated our product's risk as follows:

* The human risk is: Moderate

* The environmental risk is: Moderate

Any use inconsistent with our recommendations may affect the risk characterization. Our sales representative will assist you to determine if your product application is consistent with our recommendations. Together we can implement an appropriate risk management process.

This product material safety data sheet provides health and safety information. The product is to be used in applications consistent with our product literature. Individuals handling this product should be informed of the recommended safety precautions and should have access to this information. For any other uses, exposures should be evaluated so that appropriate handling practices and training programs can be established to insure safe workplace operations. Please consult your local sales representative for any further information.

REFERENCES

Threshold Limit Values for Chemical Substances and Physical Agents and Biological Exposure Indices, American Conference of Governmental Industrial Hygienists, OH., (Ariel Insight# CD-ROM Version), Ariel Research Corp., Bethesda, MD.

Hazardous Substances Data Bank, National Library of Medicine, Bethesda, Maryland (TOMES CPS# CD-ROM Version), Micromedex, Inc., Englewood, CO.

IARC Monographs on the Evaluation of the Carcinogenic Risk of Chemicals to Man, Geneva: World Health Organization, International Agency for Research on Cancer.

Integrated Risk Information System, U.S. Environmental Protection Agency, Washington, D.C. (TOMES CPS# CD-ROM Version), Micromedex, Inc., Englewood, CO.

Annual Report on Carcinogens, National Toxicology Program, U.S. Department of Health and Human Services, Public Health Service.

Title 29 Code of Federal Regulations, Part 1910, Subpart Z, Toxic and Hazardous Substances, Occupational Safety and Health Administration (OSHA), (Ariel Insight# CD-ROM Version), Ariel Research Corp., Bethesda, MD.

Registry of Toxic Effects of Chemical Substances, National Institute for Occupational Safety and Health, Cincinnati, OH, (TOMES CPS# CD-ROM Version), Micromedex, Inc., Englewood, CO.

Ariel Insight# (An integrated guide to industrial chemicals covered under major regulatory and advisory programs), North American Module, Western European Module, Chemical Inventories Module and the Generics Module (Ariel Insight# CD-ROM Version), Ariel Research Corp., Bethesda, MD.

The Teratogen Information System, University of Washington, Seattle, WA (TOMES CPS# CD-ROM Version), Micromedex, Inc., Englewood, CO.

Prepared By : Product Safety Department
Date issued : 04/26/2006
Version Number : 1.16

MATERIAL SAFETY DATA SHEET

PRODUCT

3980 MICROORGANISM CONTROL CHEMICAL

EMERGENCY TELEPHONE NUMBER(S)

(800) 424-9300 (24 Hours) CHEMTREC

1. CHEMICAL PRODUCT AND COMPANY IDENTIFICATION

PRODUCT NAME : 3980 MICROORGANISM CONTROL CHEMICAL

COMPANY IDENTIFICATION : Nalco Company
1601 W. Diehl Road
Naperville, Illinois
60563-1198

EMERGENCY TELEPHONE NUMBER(S) : (800) 424-9300 (24 Hours) CHEMTREC

NFPA 704M/HMIS RATING
HEALTH : 3 / 3 FLAMMABILITY : 0 / 0 INSTABILITY : 0 / 0 OTHER :
0 = Insignificant 1 = Slight 2 = Moderate 3 = High 4 = Extreme

2. COMPOSITION/INFORMATION ON INGREDIENTS

Our hazard evaluation has identified the following chemical substance(s) as hazardous. Consult Section 15 for the nature of the hazard(s).

Hazardous Substance(s)	CAS NO	% (w/w)
5-Chloro-2-Methyl-4-Isothiazolin-3-one	26172-55-4	1 - 5
2-Methyl-4-Isothiazolin-3-one	2682-20-4	0.1 - 1
Magnesium Nitrate	10377-60-3	1 - 5

3. HAZARDS IDENTIFICATION

****EMERGENCY OVERVIEW****

DANGER

CORROSIVE. CAUSES IRREVERSIBLE EYE DAMAGE OR SKIN BURNS. HARMFUL IF INHALED, SWALLOWED OR ABSORBED THROUGH SKIN. Do not get in eyes, on skin or on clothing. Prolonged or frequently repeated skin contact may cause allergic reaction in some individuals.
Mixers, loaders, and others exposed to this product must wear: long-sleeved shirt and long pants; chemical resistant gloves such as nitrile or butyl rubber; shoes plus socks; goggles and face shield; and chemical resistant apron. Discard clothing or other absorbent materials that have been drenched or heavily contaminated with this product's concentrate. Do not reuse them. Follow manufacturer's instructions for cleaning/maintaining PPE. If no such instructions for washables exist, use detergent and hot water. Keep and wash PPE separately from other laundry. Users should wash hands before eating, drinking, chewing gum, using tobacco or using the toilet. Users should remove clothing immediately if pesticide gets inside. Then wash thoroughly and put on clean clothing. Users should remove PPE immediately after handling the product. Wash the outside of gloves before removing. As soon as possible, wash thoroughly. Do not apply this product in a way that will contact workers or other persons. May evolve oxides of carbon (COx) under fire conditions. May evolve HCl under fire conditions. May evolve oxides of nitrogen (NOx) and sulfur (SOx) under fire conditions. Not flammable or combustible.

PRIMARY ROUTES OF EXPOSURE :
Eye, Skin

HUMAN HEALTH HAZARDS - ACUTE :

EYE CONTACT :
Corrosive. Will cause eye burns and permanent tissue damage.

SKIN CONTACT :
May cause severe irritation or tissue damage depending on the length of exposure and the type of first aid administered. Repeated or prolonged contact may cause skin sensitization.

INGESTION :
Not a likely route of exposure. Corrosive; causes chemical burns to the mouth, throat and stomach.

INHALATION :
Not a likely route of exposure. Irritating, in high concentrations, to the eyes, nose, throat and lungs.

SYMPTOMS OF EXPOSURE :
Acute :
A review of available data does not identify any symptoms from exposure not previously mentioned.
Chronic :
A review of available data does not identify any symptoms from exposure not previously mentioned.

AGGRAVATION OF EXISTING CONDITIONS :
A review of available data does not identify any worsening of existing conditions.

4. FIRST AID MEASURES

IF IN EYES: Hold eyes open and rinse slowly and gently with water for 15-20 minutes. Remove contact lenses, if present, after the first 5 minutes, then continue rinsing. Call a poison control center or doctor for treatment advice.

IF SWALLOWED: Call a poison control center or doctor immediately for treatment advice. Have person sip a glass of water if able to swallow. Do not induce vomiting unless told by a poison control center or doctor.

IF ON SKIN: Take off contaminated clothing. Rinse skin immediately with plenty of water for 15-20 minutes. Call a poison control center or doctor for treatment advice.

IF INHALED: Move person to fresh air. If person is not breathing, call 911 or ambulances, then give artificial respiration, preferably mouth-to-mouth, if possible. Call a poison control center or doctor for treatment advice

NOTE TO PHYSICIAN :
Probable mucosal damage may contraindicate the use of gastric lavage. Based on the individual reactions of the patient, the physician's judgement should be used to control symptoms and clinical condition.

5. FIRE FIGHTING MEASURES

FLASH POINT : None

EXTINGUISHING MEDIA :
Not expected to burn.. Use extinguishing media appropriate for surrounding fire.

FIRE AND EXPLOSION HAZARD :
May evolve oxides of carbon (COx) under fire conditions. May evolve HCl under fire conditions. May evolve oxides of nitrogen (NOx) and sulfur (SOx) under fire conditions. Not flammable or combustible.

SPECIAL PROTECTIVE EQUIPMENT FOR FIRE FIGHTING :
In case of fire, wear a full face positive-pressure self contained breathing apparatus and protective suit.

6. ACCIDENTAL RELEASE MEASURES

PERSONAL PRECAUTIONS :
Restrict access to area as appropriate until clean-up operations are complete. Ensure clean-up is conducted by trained personnel only. Ventilate spill area if possible. Do not touch spilled material. Stop or reduce any leaks if it is safe to do so. Use personal protective equipment recommended in Section 8 (Exposure Controls/Personal Protection). Notify appropriate government, occupational health and safety and environmental authorities.

METHODS FOR CLEANING UP :
SMALL SPILLS: Soak up spill with absorbent material. Place residues in a suitable, covered, properly labeled container. Wash affected area. LARGE SPILLS: Soak up with inert absorbent material. Transfer contaminated material to suitable containers for disposal. Contaminated surfaces should be swabbed with deactivation solution, let stand for 30 minutes and rinse thoroughly with clean water. DO NOT add deactivation solution to the waste container to deactivate the absorbed material. *DEACTIVATION SOLUTION - prepare fresh a solution of 5% Sodium bicarbonate and 5% Sodium hypochlorite in water. Use a ratio of 10 volumes decontamination solution per estimated volume of residual spill. Wash site of spillage thoroughly with water. Contact an approved waste hauler for disposal of contaminated recovered material. Dispose of material in compliance with regulations indicated in Section 13 (Disposal Considerations).

ENVIRONMENTAL PRECAUTIONS :
This pesticide is toxic to fish and wildlife. Do not discharge effluent containing this product into lakes, streams, ponds, estuaries, oceans or other waters, unless in accordance with the requirements of a National Pollutant Discharge Elimination System (NPDES) permit and the permitting authority has been notified in writing prior to discharge. Do not discharge effluent containing this product to sewer systems without previously notifying the local sewage treatment plant authority. For guidance contact your State Water Board or Regional Office of the EPA. Do not contaminate water by cleaning of equipment or disposal of waste. Apply this pesticide only as specified on this label.

7. HANDLING AND STORAGE

HANDLING :
Do not get in eyes, on skin, on clothing. Do not take internally. Use with adequate ventilation. Avoid generating aerosols and mists. Keep the containers closed when not in use. Have emergency equipment (for fires, spills, leaks, etc.) readily available.

STORAGE CONDITIONS :
Store the containers tightly closed. Store separately from oxidizers. Store in suitable labelled containers.

SUITABLE CONSTRUCTION MATERIAL :
Stainless Steel 316L, Polyethylene, Polypropylene, Viton

UNSUITABLE CONSTRUCTION MATERIAL :
Steel

8. EXPOSURE CONTROLS/PERSONAL PROTECTION

OCCUPATIONAL EXPOSURE LIMITS :
This product contains the following component(s) with a recognised or recommended OEL value:
Manufacturer's Recommendation :
Substance(s)

5-Chloro-2-Methyl-4-Isothiazolin-3-one	TWA: 0.076 mg/m3 STEL: 0.23 mg/m3

Manufacturer's Recommendation :
Substance(s)

2-Methyl-4-Isothiazolin-3-one	TWA: 1.5 mg/m3 STEL: 4.5 mg/m3

ENGINEERING MEASURES :
General ventilation is recommended. Use local exhaust ventilation if necessary to control airborne mist and vapor.

RESPIRATORY PROTECTION :
If significant mists, vapors or aerosols are generated an approved respirator is recommended. A suitable filter material depends on the amount and type of chemicals being handled. Consider the use of filter type: Particulate filter - HEPA. In event of emergency or planned entry into unknown concentrations a positive pressure, full-facepiece SCBA should be used. If respiratory protection is required, institute a complete respiratory protection program including selection, fit testing, training, maintenance and inspection.

HAND PROTECTION :
PVC gloves

SKIN PROTECTION :
Wear chemical resistant apron, chemical splash goggles, impervious gloves and boots. A full slicker suit is recommended if gross exposure is possible.

EYE PROTECTION :
Wear a face shield with chemical splash goggles.

HYGIENE RECOMMENDATIONS :
Eye wash station and safety shower are necessary. If clothing is contaminated, remove clothing and thoroughly wash the affected area. Launder contaminated clothing before reuse.

9. PHYSICAL AND CHEMICAL PROPERTIES

PHYSICAL STATE	Liquid
APPEARANCE	Light green Light yellow

ODOR	Mild
SPECIFIC GRAVITY	1.026
DENSITY	8.5 lb/gal
SOLUBILITY IN WATER	Complete
pH (100 %)	3.0 - 5.0
FREEZING POINT	25 °F / -4 °C
BOILING POINT	/ 100 °C
VOC CONTENT	0.80 % EPA Method 24

Note: These physical properties are typical values for this product and are subject to change.

10. STABILITY AND REACTIVITY

STABILITY :
Stable under normal conditions.

HAZARDOUS POLYMERIZATION :
Hazardous polymerization will not occur.

CONDITIONS TO AVOID :
Freezing temperatures.

MATERIALS TO AVOID :
Contact with strong oxidizers (e.g. chlorine, peroxides, chromates, nitric acid, perchlorate, concentrated oxygen, permanganate) may generate heat, fires, explosions and/or toxic vapors.

HAZARDOUS DECOMPOSITION PRODUCTS :
Under fire conditions: Oxides of carbon, Oxides of nitrogen, Oxides of sulfur, HCl

11. TOXICOLOGICAL INFORMATION

The following results are for the product along with results on the active substances.

ACUTE ORAL TOXICITY :

Species	LD50	Test Descriptor
Rat	3,810 mg/kg	Product

Rating : Non-Hazardous

ACUTE DERMAL TOXICITY :

Species	LD50	Test Descriptor
Rabbit	> 5,000 mg/kg	Product

Rating : Non-Hazardous

ACUTE INHALATION TOXICITY :

Species	LC50	Test Descriptor
Rat	13.7 mg/l (4 hrs)	Product

Rating : Toxic

PRIMARY SKIN IRRITATION : A 1.5% active solution is corrosive to skin, a 0.6% active solution is a severe skin irritant, a 0.3% active solution is a moderate skin irritant and a 0.06% active solution is a non-irritant.

PRIMARY EYE IRRITATION : A 1.5% active solution is corrosive to the eyes, a 0.3% active solution is an eye irritant and 0.06% active solution is a non-irritant.

SENSITIZATION :
Repeated or prolonged contact may cause sensitization in some individuals. A Guinea pig (Buehler Technique) sensitization study with an induction dosage of 90 ppm of active ingredients followed by an insult of 429 ppm of active ingredients was positive. A human repeated insult patch study of 28 ppm active ingredients followed by an insult of 56 ppm of active ingredients resulted in no effect to the subjects tested.

CHRONIC TOXICITY DATA :
A 90-day dietary study in dogs of 840 ppm of isothiazolinone resulted in no mortalities or pathological findings. A 90-day dermal study in rabbits of 0.4 mg/kg/day of isothiazolinone resulted in irritation but no pathological effects. A 30-month skin painting study with mice using 400 ppm isothiazolinone three times per week showed no increased tumor frequency over control. A teratology study with rabbits and rats was negative using dosages of 1.5 to 15 mg/kg isothiazolinone. Mutagenicity results have been equivocal.

CARCINOGENICITY :
None of the substances in this product are listed as carcinogens by the International Agency for Research on Cancer (IARC), the National Toxicology Program (NTP) or the American Conference of Governmental Industrial Hygienists (ACGIH).

HUMAN HAZARD CHARACTERIZATION :
Based on our hazard characterization, the potential human hazard is: High

12. ECOLOGICAL INFORMATION

ECOTOXICOLOGICAL EFFECTS :

The following results are for the product along with results on the active substances.

ACUTE FISH RESULTS :

Species	Exposure	LC50	Test Descriptor
Sheepshead Minnow	96.00 hrs	32.000 mg/l	Product
Bluegill Sunfish	96 hrs	18.67 mg/l	Product
Fathead Minnow	144 hrs	8 mg/l	Product
Rainbow Trout	96 hrs	12.67 mg/l	Product
Inland Silverside	96 hrs	16.62 mg/l	Product

ACUTE INVERTEBRATE RESULTS :

Species	Exposure	LC50	EC50	Test Descriptor
Mysid Shrimp (Mysidopsis bahia)	96.00 hrs	18.000 mg/l		Product
Ceriodaphnia dubia	48 hrs	15 mg/l		Product

Daphnia magna	48 hrs	8.7 - 12 mg/l		Product
Blue Mussel	48 hrs	865 mg/l		Product
American Oyster	48 hrs	1,730 mg/l		Product

AVIAN RESULTS :

Species	Exposure	LC50	Test Descriptor
Bobwhite Quail	8 Days	> 60 mg/kg > 560 ppm	

PERSISTENCY AND DEGRADATION :

Total Organic Carbon (TOC) : 7,850 mg/l

Chemical Oxygen Demand (COD) : 20,000 mg/l

The degradation of the major active substance begins with ring opening and elimination of chloride ion. Degradation leads to the formation of a variety of small organic acids, methylamine, carbon dioxide and elemental sulfur. The half life of each active substance is dependent upon the initial concentration.

MOBILITY :
The environmental fate was estimated using a level III fugacity model embedded in the EPI (estimation program interface) Suite TM , provided by the US EPA. The model assumes a steady state condition between the total input and output. The level III model does not require equilibrium between the defined media. The information provided is intended to give the user a general estimate of the environmental fate of this product under the defined conditions of the models. If released into the environment this material is expected to distribute to the air, water and soil/sediment in the approximate respective percentages;

Air	Water	Soil/Sediment
<5%	30 - 50%	50 - 70%

The portion in water is expected to be soluble or dispersible.

BIOACCUMULATION POTENTIAL
This preparation or material is not expected to bioaccumulate.

ENVIRONMENTAL HAZARD AND EXPOSURE CHARACTERIZATION
Based on our hazard characterization, the potential environmental hazard is: Moderate

If released into the environment, see CERCLA/SUPERFUND in Section 15.

13. DISPOSAL CONSIDERATIONS

If this product becomes a waste, it could meet the criteria of a hazardous waste as defined by the Resource Conservation and Recovery Act (RCRA) 40 CFR 261. Before disposal, it should be determined if the waste meets the criteria of a hazardous waste.

Pesticide wastes are toxic. Improper disposal of excess pesticide, spray mixture, or rinsate is a violation of Federal law. If these wastes cannot be disposed of by use according to label instructions, contact your State Pesticide or

Environmental Control Agency, or the Hazardous Waste Representative at the nearest EPA Regional Office for guidance.

Metal Containers: Triple rinse (or equivalent). Then offer for recycling or reconditioning, or puncture and dispose of in a sanitary landfill, or other procedures approved by state and local authorities. Plastic Containers: ^PLASTIC CONTAINERS: Do not reuse empty container. Triple rinse (or equivalent). Then puncture and dispose of in a sanitary landfill, or, if allowed by state and local authorities, by burning. If burned, stay out of smoke.

14. TRANSPORT INFORMATION

The information in this section is for reference only and should not take the place of a shipping paper (bill of lading) specific to an order. Please note that the proper Shipping Name / Hazard Class may vary by packaging, properties, and mode of transportation. Typical Proper Shipping Names for this product are as follows.

LAND TRANSPORT :

Proper Shipping Name :	CORROSIVE LIQUID, ACIDIC, ORGANIC, N.O.S.
Technical Name(s) :	ISOTHIAZOLINONE MICROBIOCIDE
UN/ID No :	UN 3265
Hazard Class - Primary :	8
Packing Group :	II
Flash Point :	None

AIR TRANSPORT (ICAO/IATA) :

Proper Shipping Name :	CORROSIVE LIQUID, ACIDIC, ORGANIC, N.O.S.
Technical Name(s) :	ISOTHIAZOLINONE MICROBIOCIDE
UN/ID No :	UN 3265
Hazard Class - Primary :	8
Packing Group :	II
IATA Cargo Packing Instructions :	812
IATA Cargo Aircraft Limit :	30 L (Max net quantity per package)

MARINE TRANSPORT (IMDG/IMO) :

Proper Shipping Name :	CORROSIVE LIQUID, ACIDIC, ORGANIC, N.O.S.
Technical Name(s) :	ISOTHIAZOLINONE MICROBIOCIDE
UN/ID No :	UN 3265
Hazard Class - Primary :	8
Packing Group :	II

15. REGULATORY INFORMATION

NATIONAL REGULATIONS, USA :

OSHA HAZARD COMMUNICATION RULE, 29 CFR 1910.1200 :
Based on our hazard evaluation, the following substance(s) in this product is/are hazardous and the reason(s) is/are shown below.

5-Chloro-2-Methyl-4-Isothiazolin-3-one : Corrosive, Sensitizer
2-Methyl-4-Isothiazolin-3-one : Corrosive, Sensitizer
Magnesium Nitrate : Eye irritant

CERCLA/SUPERFUND, 40 CFR 117, 302 :
Notification of spills of this product is not required.

SARA/SUPERFUND AMENDMENTS AND REAUTHORIZATION ACT OF 1986 (TITLE III) - SECTIONS 302, 311, 312, AND 313 :

SECTION 302 - EXTREMELY HAZARDOUS SUBSTANCES (40 CFR 355) :
This product does not contain substances listed in Appendix A and B as an Extremely Hazardous Substance.

SECTIONS 311 AND 312 - MATERIAL SAFETY DATA SHEET REQUIREMENTS (40 CFR 370) :
Our hazard evaluation has found this product to be hazardous. The product should be reported under the following indicated EPA hazard categories:

X	Immediate (Acute) Health Hazard
X	Delayed (Chronic) Health Hazard
-	Fire Hazard
-	Sudden Release of Pressure Hazard
-	Reactive Hazard

Under SARA 311 and 312, the EPA has established threshold quantities for the reporting of hazardous chemicals. The current thresholds are: 500 pounds or the threshold planning quantity (TPQ), whichever is lower, for extremely hazardous substances and 10,000 pounds for all other hazardous chemicals.

SECTION 313 - LIST OF TOXIC CHEMICALS (40 CFR 372) :
This product contains the following substance(s), (with CAS # and % range) which appear(s) on the List of Toxic Chemicals

Hazardous Substance(s)	CAS NO	% (w/w)
Magnesium Nitrate	10377-60-3	1.0 - 5.0

TOXIC SUBSTANCES CONTROL ACT (TSCA) :
This product is exempted under TSCA and regulated under FIFRA. The inerts are on the Inventory List.

FEDERAL INSECTICIDE, FUNGICIDE AND RODENTICIDE ACT (FIFRA) :
EPA Reg. No. 68708-1 CANCELLED
In all cases follow instructions on the product label.

FEDERAL WATER POLLUTION CONTROL ACT, CLEAN WATER ACT, 40 CFR 401.15 / formerly Sec. 307, 40 CFR 116.4 / formerly Sec. 311 :
This product contains the following substances listed in the regulation:

Substance(s)	Citations
• Cupric Nitrate	Sec. 307, Sec. 311

CLEAN AIR ACT, Sec. 112 (40 CFR 61, Hazardous Air Pollutants), Sec. 602 (40 CFR 82, Class I and II Ozone Depleting Substances) :
None of the substances are specifically listed in the regulation.

CALIFORNIA PROPOSITION 65 :
This product does not contain substances which require warning under California Proposition 65.

MICHIGAN CRITICAL MATERIALS :
This product contains the following substances listed in the regulation:

Copper

STATE RIGHT TO KNOW LAWS :
The following substances are disclosed for compliance with State Right to Know Laws:

Copper	7440-50-8
Magnesium Nitrate	10377-60-3

NATIONAL REGULATIONS, CANADA :

WORKPLACE HAZARDOUS MATERIALS INFORMATION SYSTEM (WHMIS) :
This product has been classified in accordance with the hazard criteria of the Controlled Products Regulations (CPR) and the MSDS contains all the information required by the CPR.

WHMIS CLASSIFICATION :
Pesticide controlled products are not regulated under WHMIS.

CANADIAN ENVIRONMENTAL PROTECTION ACT (CEPA) :
The substances in this preparation are listed on the Domestic Substances List (DSL), are exempt, or have been reported in accordance with the New Substances Notification Regulations.

INTERNATIONAL CHEMICAL CONTROL LAWS

AUSTRALIA
All substances in this product comply with the National Industrial Chemicals Notification & Assessment Scheme (NICNAS).

EUROPE
The substances in this preparation have been reviewed for compliance with the EINECS or ELINCS inventories.

JAPAN
All substances in this product comply with the Law Regulating the Manufacture and Importation Of Chemical Substances and are listed on the Ministry of International Trade & industry List (MITI).

KOREA
All substances in this product comply with the Toxic Chemical Control Law (TCCL) and are listed on the Existing Chemicals List (ECL)

THE PHILIPPINES
All substances in this product comply with the Republic Act 6969 (RA 6969) and are listed on the Philippine Inventory of Chemicals & Chemical Substances (PICCS).

16. OTHER INFORMATION

This product material safety data sheet provides health and safety information. The product is to be used in applications consistent with our product literature. Individuals handling this product should be informed of the recommended safety precautions and should have access to this information. For any other uses, exposures should be evaluated so that appropriate handling practices and training programs can be established to insure safe workplace operations. Please consult your local sales representative for any further information.

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Title 29 Code of Federal Regulations, Part 1910, Subpart Z, Toxic and Hazardous Substances, Occupational Safety and Health Administration (OSHA), (Ariel Insight# CD-ROM Version), Ariel Research Corp., Bethesda, MD.

Registry of Toxic Effects of Chemical Substances, National Institute for Occupational Safety and Health, Cincinnati, OH, (TOMES CPS# CD-ROM Version), Micromedex, Inc., Englewood, CO.

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Prepared By : Product Safety Department
Date issued : 04/26/2006
Version Number : 1.13

PRIORITIZATION
FOR

NORTHERN CALIFORNIA POWER
Project # 1083490
Region (N) Facility (2697)

DEVICE NUMBER 5

DEVICE NAME 1885.3 MMBTU/HR NG TURBINE WITH 222 MMBTU/HR NG BURNER

				Emissions and Potency Method			Despersion Adjustment Method		
				Prioritization Scores			Prioritization Scores		
CAS NUMBER	POLLUTANT NAME	LBS/YEAR	LBS/HOUR	Cancer	CHRONIC	ACUTE	Cancer	CHRONIC	ACUTE
1151	PAHs, total, w/o individ. components reported	3.31E+00	3.78E-04	6.19E+00			1.02E-01		
50000	Formaldehyde	1.56E+03	1.78E-01	1.59E+01	8.91E+00	2.83E+00	2.61E-01	1.48E-01	4.72E-02
50000	Formaldehyde	7.00E+00	7.99E-04	7.14E-02	4.01E-02	1.28E-02	1.18E-03	6.68E-04	2.13E-04
50328	Benzo[a]pyrene	1.94E-01	2.22E-05	3.64E-01			5.99E-03		
71432	Benzene	3.31E+00	3.77E-04	1.63E-01	9.46E-04	4.35E-04	2.68E-03	1.56E-05	7.26E-06
71432	Benzene	1.87E+02	2.14E-02	9.22E+00	5.35E-02	2.46E-02	1.52E-01	8.92E-04	4.11E-04
75070	Acetaldehyde	6.13E+02	6.99E-02	2.81E+00	1.17E+00		4.63E-02	1.95E-02	
75070	Acetaldehyde	1.75E+00	2.00E-04	8.03E-03	3.34E-03		1.32E-04	5.57E-05	
91203	Naphthalene	5.83E-01	6.66E-05	3.37E-02	1.11E-03		5.55E-04	1.86E-05	
91203	Naphthalene	1.32E+01	1.51E-03	7.66E-01	2.53E-02		1.26E-02	4.21E-04	
100414	Ethyl benzene	3.89E+00	4.44E-04	1.65E-02	3.34E-05		2.72E-04	5.57E-07	
100414	Ethyl benzene	2.19E+02	2.49E-02	9.29E-01	1.88E-03		1.53E-02	3.13E-05	
107028	Acrolein	1.56E+00	1.78E-04		4.45E-01	1.40E+00		7.42E-03	2.34E-02
107028	Acrolein	1.49E+02	1.70E-02		4.26E+01	1.34E+02		7.11E-01	2.24E+00
108883	Toluene	1.20E+03	1.37E-01		6.88E-02	5.56E-03		1.15E-03	9.27E-05
108883	Toluene	1.52E+01	1.73E-03		8.68E-04	7.02E-05		1.45E-05	1.17E-06
110543	Hexane	2.90E+04	3.31E+00		7.11E-02			1.18E-03	
110543	Hexane	2.53E+00	2.89E-04		6.20E-06			1.03E-07	
115071	Propylene	1.74E+04	1.99E+00		9.97E-02			1.66E-03	
115071	Propylene	3.02E+01	3.45E-03		1.73E-04			2.88E-06	
1330207	Xylenes (mixed)	4.78E+02	5.46E-02		1.17E-02	3.72E-03		1.96E-04	6.21E-05
1330207	Xylenes (mixed)	1.13E+01	1.29E-03		2.77E-04	8.78E-05		4.61E-06	1.46E-06
	TOTALS FOR DEVICE 5			3.65E+01	5.35E+01	1.39E+02	6.00E-01	8.92E-01	2.31E+00

Stack Height over 20 Meters

PRIORITIZATION
FOR

NORTHERN CALIFORNIA POWER
Project # 1083490
Region (N) Facility (2697)

DEVICE NUMBER 6
DEVICE NAME COOLING TOWERS

CAS NUMBER	POLLUTANT NAME	LBS/YEAR	LBS/HOUR	Emissions and Potency Method Prioritization Scores Cancer	CHRONIC	ACUTE	Despersion Adjustment Method Prioritization Scores Cancer	CHRONIC	ACUTE
7440508	Copper	1.00E-04	8.84E-09		7.15E-07	1.33E-07		1.19E-08	2.21E-09
	TOTALS FOR DEVICE 6			0.00E+00	7.15E-07	1.33E-07	0.00E+00	1.19E-08	2.21E-09

DEVICE NUMBER 7
DEVICE NAME 65 MMBTU/HR NG BOILER

CAS NUMBER	POLLUTANT NAME	LBS/YEAR	LBS/HOUR	Emissions and Potency Method Prioritization Scores Cancer	CHRONIC	ACUTE	Despersion Adjustment Method Prioritization Scores Cancer	CHRONIC	ACUTE
50000	Formaldehyde	7.00E+00	7.99E-04	7.14E-02	4.01E-02	1.28E-02	1.18E-03	6.68E-04	2.13E-04
50328	Benzo[a]pyrene	5.69E-02	6.50E-06	1.06E-01			1.75E-03		
71432	Benzene	3.30E+00	3.77E-04	1.63E-01	9.45E-04	4.35E-04	2.68E-03	1.58E-05	7.25E-06
75070	Acetaldehyde	1.77E+00	2.02E-04	8.10E-03	3.37E-03		1.33E-04	5.61E-05	
91203	Naphthalene	1.71E-01	1.95E-05	9.87E-03	3.26E-04		1.63E-04	5.43E-06	
100414	Ethyl benzene	3.93E+00	4.48E-04	1.67E-02	3.37E-05		2.75E-04	5.62E-07	
107028	Acrolein	1.54E+00	1.76E-04		4.40E-01	1.39E+00		7.33E-03	2.31E-02
108883	Toluene	1.51E+01	1.72E-03		8.64E-04	6.98E-05		1.44E-05	1.16E-06
110543	Hexane	2.62E+00	2.99E-04		6.42E-06			1.07E-07	
115071	Propylene	3.02E+02	3.44E-02		1.73E-03			2.88E-05	
1330207	Xylenes (mixed)	1.12E+01	1.28E-03		2.75E-04	8.73E-05		4.59E-06	1.46E-06
	TOTALS FOR DEVICE 7			3.75E-01	4.88E-01	1.40E+00	6.18E-03	8.13E-03	2.33E-02

PRIORITIZATION
FOR

NORTHERN CALIFORNIA POWER
Project # 1083490
Region (N) Facility (2697)

Emissions and Potency Method

Prioritization Scores

Cancer	CHRONIC	ACUTE
3.68E+01	5.40E+01	1.40E+02

TS = Total Score
t = Specific Toxic Substance
EYR = Emissions Lbs / Year
EHR = Emissions Lbs / Hour
NF = Normalization Factor (Cancer = 1700, Acute = 1500, Chronic = 150)
URF = Unit Risk Factor
AREL = Acute Reference Exposure Level
CREL = Chronic Reference Exposure Level
RP = Receptor Proximity Adjustment Factor
R = Receptor Distance

	RP
0m < R < 100m	1.0
100m < R < 250m	0.25
250m < R < 500m	0.04
500m < R < 1000m	0.011
1000m < R < 1500m	0.003
1500m < R < 2000m	0.002
R > 2000m	0.001

Cancer Score:
TS(t) = EYR(t) * URF(t) * RP * 1700

Acute Score:
TS(t) = [EHR(t) / AREL(t)] * RP * 1500

Chronic Score:
TS(t) = { ([EYR(t) / Hours Of Operation] / CREL(t)) * RP * 150 }

Dispersion Adjustment Method

Prioritization Scores

Cancer	CHRONIC	ACUTE
6.07E-01	9.00E-01	2.33E+00

TS = Total Score
t = Specific Toxic Substance
EYR = Emissions Lbs / Year
EHR = Emissions Lbs / Hour
NF = Normalization Factor (Cancer = 28, Acute = 25, Chronic = 2.5)
URF = Unit Risk Factor
AREL = Acute Reference Exposure Level
CREL = Chronic Reference Exposure Level
SHA = Stack Height Adjustment (< 20m = 60, < 45m = 9, >= 45m = 1)
RP = Receptor Proximity Adjustment Factor
R = Receptor Distance
H = Stack Height

For Stack - 0m <= H < 20m	RP	For Stack - 20m <= H < 45m	RP	For Stack - >= H < 45m	RP
0m < R < 100m	1.0	0m < R < 100m	1.0	0m < R < 100m	1.0
100m < R < 250m	0.25	100m < R < 250m	0.85	100m < R < 250m	1.0
250m < R < 500m	0.04	250m < R < 500m	0.22	250m < R < 500m	0.90
500m < R < 1000m	0.011	500m < R < 1000m	0.064	500m < R < 1000m	0.40
1000m < R < 1500m	0.003	1000m < R < 1500m	0.018	1000m < R < 1500m	0.13
1500m < R < 2000m	0.002	1500m < R < 2000m	0.009	1500m < R < 2000m	0.066
R > 2000m	0.001	R > 2000m	0.006	R > 2000m	0.042

Cancer Score:
TS(t) = EYR(t) * URF(t) * RP * SHA * 28

Acute Score:
TS(t) = [EHR(t) / AREL(t)] * RP * SHA * 25

Chronic Score:
TS(t) = { ([EYR(t) / Hours Of Operation] / CREL(t)) * RP * SHA * 2.5 }

FILE: c:\HARP\projects\demo\Rep_PMI.txt

NCPA
N-2697-5-0
NG Turbine &
NG Burner

EXCEPTION REPORT
(there have been no changes or exceptions)

RECEPTORS WITH HIGHEST CANCER RISK

REC	TYPE	CANCER	CHRONIC	ACUTE	UTME	UTMN	ZONE
3620	GRID	4.57E-07	5.61E-03	1.41E-02	641989	4216350	11
3621	GRID	4.56E-07	5.60E-03	1.42E-02	642006	4216366	11
3619	GRID	4.55E-07	5.59E-03	1.46E-02	641972	4216335	11
4740	GRID	4.52E-07	5.55E-03	1.44E-02	641987	4216388	11
3618	GRID	4.49E-07	5.51E-03	1.48E-02	641955	4216319	11
2909	GRID	4.49E-07	5.52E-03	1.39E-02	642022	4216390	11
4756	GRID	4.44E-07	5.45E-03	1.30E-02	642071	4216333	11
3633	GRID	4.41E-07	5.41E-03	1.49E-02	642051	4216276	11
4757	GRID	4.41E-07	5.42E-03	1.30E-02	642074	4216374	11
3632	GRID	4.40E-07	5.40E-03	1.48E-02	642033	4216261	11

RECEPTORS WITH HIGHEST CHRONIC HI

REC	TYPE	CANCER	CHRONIC	ACUTE	UTME	UTMN	ZONE
3620	GRID	4.57E-07	5.61E-03	1.41E-02	641989	4216350	11
3621	GRID	4.56E-07	5.60E-03	1.42E-02	642006	4216366	11
3619	GRID	4.55E-07	5.59E-03	1.46E-02	641972	4216335	11
4740	GRID	4.52E-07	5.55E-03	1.44E-02	641987	4216388	11
2909	GRID	4.49E-07	5.52E-03	1.39E-02	642022	4216390	11
3618	GRID	4.49E-07	5.51E-03	1.48E-02	641955	4216319	11
4756	GRID	4.44E-07	5.45E-03	1.30E-02	642071	4216333	11
4757	GRID	4.41E-07	5.42E-03	1.30E-02	642074	4216374	11
2910	GRID	4.40E-07	5.41E-03	1.42E-02	642028	4216416	11
3633	GRID	4.41E-07	5.41E-03	1.49E-02	642051	4216276	11

RECEPTORS WITH HIGHEST ACUTE HI

REC	TYPE	CANCER	CHRONIC	ACUTE	UTME	UTMN	ZONE
79	GRID	6.87E-08	8.44E-04	1.84E-02	641258	4217225	11
4754	GRID	3.15E-07	3.87E-03	1.83E-02	641847	4216128	11
3622	GRID	3.14E-07	3.85E-03	1.83E-02	641862	4216107	11
7581	GRID	6.76E-08	8.30E-04	1.83E-02	641260	4217248	11
4772	GRID	3.00E-07	3.68E-03	1.82E-02	641890	4216051	11
4771	GRID	2.68E-07	3.29E-03	1.81E-02	641853	4216030	11
4753	GRID	2.77E-07	3.40E-03	1.80E-02	641811	4216107	11
3636	GRID	2.89E-07	3.55E-03	1.79E-02	641906	4216017	11
80	GRID	7.03E-08	8.64E-04	1.79E-02	641237	4217216	11
78	GRID	6.63E-08	8.15E-04	1.79E-02	641280	4217234	11

FILE: c:\HARP\projects\demo\Rep_PMI.txt

NCPA

N-2697-7-0

NG Boiler

EXCEPTION REPORT
(there have been no changes or exceptions)

RECEPTORS WITH HIGHEST CANCER RISK

REC	TYPE	CANCER	CHRONIC	ACUTE	UTME	UTMN	ZONE
2863	GRID	3.34E-07	2.40E-03	4.98E-02	641622	4216646	11
2871	GRID	3.04E-07	2.19E-03	1.07E-02	641697	4216653	11
8103	GRID	3.04E-07	2.19E-03	5.20E-02	641593	4216643	11
8102	GRID	3.03E-07	2.18E-03	5.23E-02	641595	4216644	11
2876	GRID	2.86E-07	2.05E-03	6.44E-03	641747	4216657	11
2870	GRID	2.86E-07	2.05E-03	4.89E-03	641691	4216629	11
2875	GRID	2.84E-07	2.04E-03	3.93E-03	641740	4216631	11
4066	GRID	2.83E-07	2.03E-03	4.26E-03	641711	4216603	11
2874	GRID	2.79E-07	2.00E-03	3.83E-03	641734	4216605	11
3572	GRID	2.77E-07	1.99E-03	2.83E-02	641607	4216622	11

RECEPTORS WITH HIGHEST CHRONIC HI

REC	TYPE	CANCER	CHRONIC	ACUTE	UTME	UTMN	ZONE
2863	GRID	3.34E-07	2.40E-03	4.98E-02	641622	4216646	11
8103	GRID	3.04E-07	2.19E-03	5.20E-02	641593	4216643	11
2871	GRID	3.04E-07	2.19E-03	1.07E-02	641697	4216653	11
8102	GRID	3.03E-07	2.18E-03	5.23E-02	641595	4216644	11
2876	GRID	2.86E-07	2.05E-03	6.44E-03	641747	4216657	11
2870	GRID	2.86E-07	2.05E-03	4.89E-03	641691	4216629	11
2875	GRID	2.84E-07	2.04E-03	3.93E-03	641740	4216631	11
4066	GRID	2.83E-07	2.03E-03	4.26E-03	641711	4216603	11
2874	GRID	2.79E-07	2.00E-03	3.83E-03	641734	4216605	11
3572	GRID	2.77E-07	1.99E-03	2.83E-02	641607	4216622	11

RECEPTORS WITH HIGHEST ACUTE HI

REC	TYPE	CANCER	CHRONIC	ACUTE	UTME	UTMN	ZONE
8102	GRID	3.03E-07	2.18E-03	5.23E-02	641595	4216644	11
8103	GRID	3.04E-07	2.19E-03	5.20E-02	641593	4216643	11
2863	GRID	3.34E-07	2.40E-03	4.98E-02	641622	4216646	11
8101	GRID	2.20E-07	1.58E-03	4.90E-02	641599	4216651	11
8099	GRID	3.88E-08	2.79E-04	4.25E-02	641585	4216665	11
8100	GRID	3.84E-08	2.75E-04	4.23E-02	641586	4216665	11
8098	GRID	1.54E-08	1.10E-04	2.96E-02	641578	4216685	11
2865	GRID	2.03E-07	1.46E-03	2.90E-02	641646	4216664	11
3572	GRID	2.77E-07	1.99E-03	2.83E-02	641607	4216622	11
8094	GRID	1.86E-08	1.33E-04	2.69E-02	641570	4216707	11

AAQA for Northern California Power Agency (NCPA) (N-2697-5-0, 6-0, 7-0)
All Values are in ug/m^3

	NOx 1 Hour	NOx Annual	CO 1 Hour	CO 8 Hour	SOx 1 Hour	SOx 3 Hour	SOx 24 Hour	SOx Annual	PM 24 Hour	PM Annual
ANPMSTK	5.987E+01	2.678E-01	3.991E+02	2.595E+02	3.492E-03	1.164E-03	2.237E-03	9.344E-02	4.102E-03	2.074E-03
PMCT1	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	3.897E-02	3.059E-01
PMCT2	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	5.204E-02	2.330E-01
PMCT3	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	1.046E-01	5.263E-02
PMCT4	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	1.148E-01	5.047E-02
PMCT5	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	8.469E-02	2.847E-02
PMCT6	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	3.060E-02	5.057E-02
PMCT7	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	2.024E-02	9.488E-04
ANPMABL	6.400E-01	3.934E-03	3.724E+00	3.784E+00	1.062E+01	6.816E+00	1.700E+00	1.748E-03	4.384E+00	1.128E-02
Background	1.014E+02	2.296E+01	3.146E+03	1.981E+03	3.464E+02	1.998E+02	8.260E+01	1.865E+01	7.300E+01	3.100E+01
Facility Totals	1.619E+02	2.323E+01	3.548E+03	2.244E+03	3.570E+02	2.067E+02	8.430E+01	1.875E+01	7.783E+01	3.174E+01
AAQS	338	56	23000	10000	655	1300	105	80	50	30
	Pass	**Pass**	**Pass**	**Pass**	**Pass**	**Pass**	**Pass**	**Pass**	~~**Fail**~~ OK	~~**Fail**~~ ok

Passes EPA's Significance Level.

EPA's Significatance Level (ug/m^3)

NOx 1 Hour	NOx Annual	CO 1 Hour	CO 8 Hour	SOx 1 Hour	SOx 3 Hour	SOx 24 Hour	SOx Annual	PM 24 Hour	PM Annual
0.0	1.0	2000.0	500.0	0.0	25.0	5.0	1.0	5.0	1.0
								4.834 < 5.0	0.7353 < 1.0

AAQA Emission (g/sec)

Device	NOx 1 Hour	NOx Annual	CO 1 Hour	CO 8 Hour	SOx 1 Hour	SOx 3 Hour	SOx 24 Hour	SOx Annual	PM 24 Hour	PM Annual
ANPMSTK	5.04E+01	2.85E+00	2.52E+02	2.52E+02	7.56E-01	7.56E-01	7.56E-01	7.47E-01	1.39E+00	1.21E+00
PMCT7	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	8.10E-03	8.10E-03
PMCT6	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	8.10E-03	8.10E-03
PMCT5	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	8.10E-03	8.10E-03
PMCT4	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	8.10E-03	8.10E-03
PMCT3	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	8.10E-03	8.10E-03
PMCT2	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	8.10E-03	8.10E-03
PMCT1	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	8.10E-03	8.10E-03
ANPMABL	6.93E-02	3.71E-03	3.02E-01	3.02E-01	2.39E-02	2.39E-02	2.39E-02	1.24E-03	6.17E-02	3.32E-03

Facility Summary

REGION N

FACID 2697

PROJECT 1083490 NORTHERN CALIFORNIA POWER

			Prioritization Scores			Risk Scores		
Unit ID	*MOD #*	*EQUIPMENT*	*CANCER*	*ACUTE*	*CHRONIC*	*CANCER*	*ACUTE*	*CHRONIC*
5	0	1885.3 MMBTU/HR NG TURBINE WITH 222 MM	0.600	2.310	0.892	4.57E-07	1.84E-02	5.61E-03
6	0	COOLING TOWERS		0.000	0.000	0.00E+00	0.00E+00	0.00E+00
7	0	65 MMBTU/HR NG BOILER	0.375	1.399	0.488	3.34E-07	5.23E-02	2.40E-03
		Project Totals	9.75E-01	3.71E+00	1.38E+00	7.91E-07	7.07E-02	8.01E-03
		Facility Totals	9.75E-01	3.71E+00	1.38E+00	7.91E-07	7.07E-02	8.01E-03

ATTACHMENT G
SO_X FOR PM_{10} INTERPOLLUTANT OFFSET ANALYSIS

Interpollutant Offset Ratio Explanation

The Air District's Rule 2201, "New and Modified Source Review", requires facilities to supply "emissions offsets" when a permittee requests new or modified permits that allow emissions of air contaminants above certain annual emission offset thresholds. In addition, Rule 2201 allows interpollutant trading of offsets amongst criteria pollutants and their precursors upon the appropriate scientific demonstration of an adequate trading ratio, herein referred to as the interpollutant ratio. A technical analysis is required to determine the interpollutant offset ratio that is justified by evaluation of atmospheric chemistry. This evaluation has been conducted using the most recent modeling analysis available for the San Joaquin Valley. The results of the analysis are designed to be protective of health for the entire Valley for the entire year, by applying the most stringent interpollutant ratio throughout the Valley.

It is appropriate for District particulate offset requirements to be achieved by either a reduction of directly emitted particulate or by reduction of the gases, called particulate precursors, which become particulates from chemical and physical processes in the atmosphere. The District interpollutant offset relationship quantifies precursor gas reductions sufficient to serve as a substitute for a required direct particulate emissions reduction. Emission control measures that reduce gas precursor emissions at the facility may be used to provide the offset reductions. Alternatively, emission credits for precursor reductions may be used in accordance with District regulations.

The amount of particulate formed by the gaseous emissions must be evaluated to determine how much credit should be given for the gaseous reductions. Gases combine and merge with other material adding molecular weight when forming into particles. Some of the gases do not become particulate matter and remain a gas. Both the extent of conversion into particles and resulting weight of the particles are considered to establish mass equivalency between direct particulate emissions and particulate formed from gas precursors. The Interpollutant offset ratio is expressed as a per-ton equivalency.

The District interpollutant analysis uses the most recent and comprehensive modeling of San Joaquin Valley particulate formation from sulfur oxides (SOx) and nitrogen oxides (NOx). Modeling compares industrial directly emitted particulate to particulate matter from precursor emissions. The interpollutant modeling procedure, assumptions and uncertainties are documented in an extensive analysis file. Additional documentation of the modeling procedure for the San Joaquin Valley is contained in the 2008 PM2.5 Plan and its appendices. The 2008 PM2.5 Plan provides evaluation of the atmospheric relationships for direct particulate emissions and precursor gases when they are highest during the fourth quarter of the year. The southern portion of the Valley is evaluated by both receptor modeling and regional modeling of chemical relationships for precursor particulate formation. Regional modeling was conducted for the entire Valley through 2014. The two modeling approaches are combined to determine interpollutant offset ratios applicable to, and protective of, the entire Valley (SOx for PM 1:1 and NOx for PM 2.629:1).

DEVELOPMENT OF THE INTERPOLLUTANT RATIO

For the proposed substitution of reductions of sulfur oxides (SOx) or nitrogen oxides (NOx) for directly emitted particulate matter

March 2009

Introduction

Goal of Interpollutant Evaluation: Establish the atmospheric exchange relationship for substitution of alternative pollutant or precursor reductions for required reductions of directly emitted particulate

Evaluation to establish the atmospheric relationship of different pollutants is required as a prerequisite for establishing procedures for allowing a required reduction to be met by substitution of a reduction of a different pollutant or pollutant precursor. Proposed new facility construction or facility modifications may result in increased emissions of a pollutant. The District establishes requirements for reductions of the pollutant to "offset" the proposed increase. A facility may propose a reduction of an alternative pollutant or pollutant precursor where reductions of that material have already been achieved at the facility beyond the amount required by District regulations or where emission reductions credits for reductions achieved by other facilities are economically available; however, for such a substitution to be allowed the District must establish equivalency standards for the substitution. The equivalency relationship used for offset requirements is referred to in this discussion as the interpollutant ratio. The interpollutant ratio is a mathematical formula expressing the amount of alternative pollutant or precursor reduction required to be substituted for the required regulatory reduction. This discussion is limited to the atmospheric relationships and does not address other policy or regulatory requirements for offsets such as are contained in District Rule 2201.

The following description is provided to explain key elements of the analysis conducted to develop the atmospheric relationship between the commonly requested substitutions. Emission reductions of sulfur oxide emissions or nitrogen oxide emissions are proposed by many facilities as a substitution for reduction of directly emitted particulates. Elemental and organic carbon emissions are the predominant case and dominant contribution to directly emitted particulate mass from industrial facilities, although other types of directly emitted particulates do occur. Therefore this atmospheric analysis examines directly emitted carbon particulates from industrial sources in comparison to the formation of particles from gaseous emissions of sulfur oxides and nitrogen oxides.

Analyses included in Interpollutant evaluation

Factors Considered

The foundation for this analysis is provided by the atmospheric modeling conducted for the 2008 PM2.5 Plan. Modeling conducted for this State Implementation Plan was conducted by the District and the California Air Resources Board using a variety of modeling approaches. Each separate model has technical limitations and uncertainties. To reduce the uncertainty of findings, a combined evaluation of results of all of the modeling methods is used to establish "weight of evidence" support for technical analysis and conclusions. The modeling methods are supported by a modeling protocol which was sent to ARB and EPA Region IX for review and was included in the appendices to the Plan.

The analysis file prepared for the interpollutant ratio evaluation includes emissions inventories, regional model daily output files, chemical mass balance modeling and speciated rollback modeling as produced for the 2008 PM2.5 Plan. This well examined and documented modeling information was used as a starting point for additional evaluation to determine interrelationships between directly emitted pollutants and particulates from precursors.

The interpollutant ratio analysis is limited to evaluation of directly emitted PM2.5 from industrial sources and formation of PM2.5 from precursor gases. While both directly emitted particulates and particulate from precursor gases also occur in the PM10 size range, there is much more uncertainty associated with deposition rates and particle formation rates for the larger size ranges. Additionally, because PM2.5 is a subset of PM10; all reductions of PM2.5 are fully creditable as reductions towards PM10 requirements. This analysis concentrates on the quarter of the year when both directly emitted carbon from industrial sources and secondary particulates are measured at the highest levels. Assessing atmospheric ratios at low concentrations is subject to much greater uncertainty and has limited value toward assessment of actions to comply with the air quality standards.

Elements from 2008 PM 2.5 Plan

- Regional modeling daily output for eleven locations
- Chemical Mass Balance (CMB) modeling for four locations – source analysis, speciation profile selection, event meteorology evaluation
- Receptor speciated rollback modeling with adjustment for nitrate nonlinearity for four locations, evaluation of spatial extent of contributing sources
- Emission inventories and projections to future years as developed for the 2008 PM 2.5 Plan

- Modeling protocols for receptor modeling, regional modeling, and Positive matrix Factorization (PMF) analysis and evaluation of technical issues applicable to particulate formation in the San Joaquin Valley
- Model performance analysis as documented in appendices to the 2008 PM 2.5 Plan

Extension by additional analysis

Additional evaluation was conducted to evaluate the receptor modeling relationship between direct PM from industrial sources and sulfate and nitrate particulate formed from SOx and NOx precursor gases. Area of influence adjustments were evaluated to ensure appropriate consideration of contributing source area for different types of pollutants for both directly emitted and secondary particulate. This evaluation was possible only for the southern four Valley counties and was conducted for both 2000 and 2009.

The regional model output was evaluated for the fourth quarter to evaluate general atmospheric chemistry in 2005 and 2014 to determine the correlation between northern and southern areas of the Valley. This evaluation determined that the atmospheric chemistry observed and modeled in the north was within the range of values observed and modeled in the southern SJV. This establishes that a ratio protective of the southern Valley will also be protective in the north.

The District determined from the additional analyses of both receptor and regional modeling that the most stringent ratio determined for the southern portion of the Valley would also be protective of the northern portion of the Valley. Due to the regional nature of these pollutants, actions taken in other counties must be assumed to have at least some influence on other counties; therefore to achieve attainment at the earliest practical date it is appropriate to require all counties to establish a consistent interpollutant ratio for the entire District.

Strengths

The interpollutant ratio analysis uses established and heavily reviewed modeling and outputs as foundation data. Analysis of model performance has already been completed for the models and for the emissions inventories used for this analysis. The modeling was performed in accordance with protocols developed by the District and ARB and in accordance with modeling guidelines established by EPA. The combination of modeling approaches provides an analysis for the current year and provides projection to 2014. Weight of evidence comparison of various modeling approaches establishes the reliability of the foundation modeling, with all modeling approaches showing strong agreement in predicted results. Additional analysis performed to develop the interpollutant ratio uses both regional and receptor evaluations which were the primary models used for the 2008 PM 2.5 Plan.

Limitations

Both industrial direct emissions and secondary formed particulate may be both PM2.5 and PM10. The majority of secondary particulates formed from precursor gases are in the PM2.5 range as are most combustion emissions from industrial stacks, however both secondary and stack emissions do contain particles larger than PM2.5. Regional modeling is more reliable for the smaller fraction due to travel distances and deposition rates. Large particles have much higher deposition and are much more difficult to replicate with a regional model. This leads to a strong technical preference for evaluating both emission types in terms of PM2.5 because the integration of receptor analysis and regional modeling for coarse particle size range up to PM10 has a much greater associated uncertainty.

Analyses contained in Receptor modeling

Factors Considered

This modeling approach uses speciated linear modeling based on chemical mass balance evaluation of contributing sources with San Joaquin Valley specific identification of contributing source profiles, adjustments from regional modeling for the nonlinearity of nitrate formation, adjustments for area of influence impacts of contributing sources developed from back trajectory analysis of high concentration particulate episodes and projections of future emission inventories as developed for the 2008 PM2.5 Plan.

Analyses in receptor modeling that use input from regional modeling

The receptor modeling analysis uses a modified projection of nitrate particulate formation from nitrogen oxides based upon results of regional modeling. The atmospheric chemistry associated with nitrate particulate formation has been determined to be nonlinear; while the default procedures for speciated rollback modeling assume a linear relationship. This adjustment has been demonstrated as effective in producing reliable atmospheric projections for the prior PM10 Plans.

Extension by additional analysis

Additional evaluations were added to results of the receptor modeling performed for the 2008 PM2.5 Plan. Calculations determine the observed micrograms per ton of emission for each contributing source category that can be resolved by chemical mass balance modeling methods. These ten categories allow differentiation of industrial direct emissions of organic and elemental carbon from other sources that emit elemental and organic carbon. The interpollutant calculation is developed as an addition to the receptor analysis by calculating the ratio of emissions per ton of directly emitted industrial PM2.5 to the per ton ratio of secondary particulate formed from NOx and SOx emissions. Summary tables and issue and documentation discussion was added to the analysis.

Strengths

Receptor modeling provides the ability to separately project the effect of different key sources contributing to carbon and organic carbon. This is critical for establishing the atmospheric relationship between industrial emissions and the observed concentrations due to industrial emissions. Regional modeling methods at this time do not support differentiation of vegetative and motor vehicle carbon contribution from the emissions form industrial sources. The area of influence of contributing sources was also considered as a factor with the methods developed by the District to incorporate the gridded footprint of contributing sources into the receptor analysis. While regional models use gridded emissions, current regional modeling methods do not reveal the resulting area of influence of contributing sources.

Limitations

Receptor modeling uses linear projections for future years and cannot account for equilibrium limitations that would occur if a key reaction became limited by reduced availability of a critical precursor due to emission reductions. The regional model was used to investigate this concern and did not project any unexpected changes due to precursor limitations.

Analyses contained in Regional modeling

Factors Considered

The analysis file includes the daily modeling output representing modeled values for the base year 2005 and predicted values for 2014 for each of the eleven Valley sites that have monitoring data for evaluation of the models performance in predicting observed conditions. These sites are located in seven of the eight Valley counties. Madera County does not have monitoring site data for this comparison.

Modeling data for all quarters of the year was provided. Due to the higher values that occur due to stagnation events in the fourth quarter, both industrial carbon concentrations and secondary particulates forming from gases are highest in the fourth quarter. Evaluating the interpollutant ratio for other quarters would be less reliable and of less significance to assisting in the reduction of high particulate concentrations. Modeling for lower values has higher uncertainty. Modeling atmospheric ratios when the air quality standard is being met are axiomatically not of value to determining offset requirements intended to assist in achieving compliance with the air quality standard. However, for consistency of analysis between sites, days when the standard was being met during the fourth quarter were not excluded from the interpollutant ratio analysis. Bakersfield fourth quarter modeled data included only eight days that were at or below the standard. Fresno and Visalia sites averaged twelve days; northern sites 24 days and the County of Kings 38 days.

Modeling output provided data for both 2005 and 2014. While there is substantial emissions change projected for this period, the regional modeling evaluation does not project much change in the atmospheric ratios of directly emitted pollutants and secondary pollutants from precursor gases. This indicates that the equilibrium processes are not expected to encounter dramatic change due to limitation of reactions by scarcity of one of the reactants. This further justifies using the receptor evaluation determining the interpollutant ratio for 2009 through the year 2014 without further adjustment. If observed air quality data demonstrates a radical shift in chemistry or components during the next few years, such a change could indicate that a limiting reaction has been reached that was not projected by the model and such radical changes might require reassessment of the conclusion that the ratio should remain unchanged through 2014.

Extension by additional analysis

Regional modeling results prepared for the 2008 PM2.5 Plan were analyzed to extract fourth quarter data for all sites. The atmospheric chemistry for all counties was analyzed for consistency and variation. This analysis provided a determination that the secondary formation chemistry and component sources contributing to concentrations observed in the north fell within the range of values similarly determined for the southern four counties. Based upon examination of the components and chemistry, the northern counties would be expected to have an interpollutant ratio value less than the ratio determined for Kern County but greater than the one for Tulare County. This establishes that the interpollutant ratio determined by receptor analysis of the southern four counties provides a value that is also sufficiently protective for the north.

Strengths

Regional models provide equilibrium based evaluations of particulate formed from precursor gases and provide a regional assessment that covers the entire Valley. The projection of particulate formed in future years is more reliable than linear methods used for receptor modeling projections.

Limitations

The regional model does not provide an ability to focus on industrial organic carbon emissions separate from other carbon sources such as motor vehicles, residential wood smoke, cooking and vegetative burning. Regional modeling does not provide an assessment method for determination of sources contributing at each site or the area of influence of contributing emissions. Receptor analysis provides a more focused tool for this aspect of the evaluation.

Results and Documentation

SJVAPCD Interpollutant Ratio Results

SOx for PM ratio: 1.000 ton of SOx per ton of PM

NOx for PM ratio: 2.629 tons of NOx per ton of PM

These ratios do not include adjustments for other regulatory requirements specified in provisions of District Rule 2201.

The results of the modeling analysis developed an atmospheric interpollutant ratio for NOx to PM of 2.629 tons of NOx per ton of PM. This result was the most stringent ratio from the assessment industrial carbon emissions to secondary particulates at Kern County; with Fresno, Tulare and Kings counties having a lower ratio. The assessment of chemistry from the regional model required comparison of total carbon to secondary particulates and is therefore not directly useful to establish a ratio. However, the regional model does provide an ability to compare the general atmospheric similarity and compare changes in chemistry due to Plan reductions. Evaluation revealed that the atmospheric chemistry of San Joaquin, Stanislaus and Merced counties falls within the range of urban characteristics evaluated for the southern four counties; therefore the ratio established should be sufficiently protective of the northern four counties. Additionally, comparison of future year chemistry showed minimal change in pollutant ratio due to the projected changes in the emission inventory from implementation of the Plan. The SOx ratio as modeled indicates a value of less than one to one due to the increase in mass for conversion of SOx to a particulate by combination with other atmospheric compounds; however, the District has set guidelines that require at least one ton of an alternative pollutant for each required ton of reduction in accordance with District Rule 2201 Section 4.13.3. Therefore the SOx interpollutant ratio is established as 1.000 ton of SOx per ton of PM. These ratios do not include adjustments for other regulatory considerations, such as other provisions of District Rule 2201.

A guide to the key technical topics and the reference material relevant to that topic is found on the next page. References from the 2008 PM2.5 Plan may be obtained by requesting a copy of that document and its appendices or by downloading the document from http://www.valleyair.org/Air_Quality_Plans/AQ_Final_Adopted_PM25_2008.htm. References in Italics are spreadsheets included in the interpollutant analysis file "09 Interpollutant Ratio Final 032909.xls" which includes 36 worksheets of receptor modeling information from the 2008 PM2.5 Plan, 11 modified and additional spreadsheets for this analysis and two spreadsheets of regional model daily output. This file is generally formatted for printing with the exception of the two spreadsheets containing the regional model output "*Model-Daily Annual*" and "*Model-Daily Q4*" which are over 300 pages of raw unformatted model output files. The remainder of the file is formatted to print at approximately 100 pages. This file will be made available on request but is not currently posted for download.

Interpollutant Ratio Issues & Documentation

	TOPIC	Reference
1	**Reason for using PM2.5 for establishing the substitution relationship between direct emitted carbon PM and secondary nitrate and sulfate PM:** consistency of relationship between secondary particulates and industrial direct carbon combustion emissions.	2008 PM2.5 Plan, Sections 3.3.2 through 3.4.2
2	**Reason for using 4th Quarter analysis:** Highest PM2.5 for all sites.	*DV Qtrs*
3	**Reason for using analysis of southern SJV sites to apply to regional interpollutant ratio:** Northern site chemistry ratios are within the range of southern SJV ratios. Peak ratio will be protective for all SJV counties.	*Q4 Model Pivot, Model-site chem, Model-Daily Q4*
4	**Reason for using combined results of receptor and regional model:** Receptor model provides breakdown of different carbon sources to isolate connection between industrial emissions and secondary PM.	2008 PM2.5 Plan, Appendix F
	Regional model provides atmospheric information concerning the northern SJV not available from receptor analysis.	2008 PM2.5 Plan, Appendix G
5	**Most significant contributions of receptor evaluation:** Separation of industrial emissions from other source types. Area of influence evaluation for contributing sources.	2008 PM2.5 Plan, Appendix F
6	**Most significant contributions of regional model:** Scientific equilibrium methods for atmospheric chemistry projections for 2014. Receptor technique is limited to linear methods.	2008 PM2.5 Plan, Appendix G
7	**Common area of influence adjustments used for all receptor evaluations:** Geologic & Construction, Tire and Brake Wear, Vegetative Burning - contribution extends from more than just the urban area (L2) Mobile exhaust (primary), Organic Carbon (Industrial) primary, Unassigned - contribution extends from more than larger area, subregional (L3) Secondary particulates from carbon sources are dominated by the local area with some contribution from the surrounding area (average of L1 and L2) Marine emissions not found present in CMB modeling for this analysis.	Modeling evaluation by J. W. Sweet February 2009 Reflected in *IPR* <u>County</u> *2000-2009* worksheets
8	**Variations to reflect secondary area of influence specific to location:** Fresno: Evaluation shows extremely strong urban signature (L1) for secondary sources Kern: Evaluation shows a strong urban signature mixed with emissions from the surrounding industrial areas (average L1 and L2) for both carbon and secondary sources Kings and Tulare: Prior evaluation has show a shared metropolitan contribution area (L2)	Modeling evaluation by J. W. Sweet February 2009 Reflected in *IPR* <u>County</u> *2000-2009* worksheets
9	**Reasons for using 2009 Interpollutant Ratio Projection:**	
	2009 Interpollutant ratio is consistent with current emissions inventories	2008 PM2.5 Plan
	Regional modeling does not show a significant change in chemical relationships through 2014.	*Q4 Model Pivot*
10	**Reason for using SOx Interpollutant Ratio at 1.000:** A minimum offset ratio is established as 1.000 to 1.000 consistent with prior District policy and procedure for interpollutant offsets.	District Rule 2201 Section 4.13.3

ATTACHMENT H
POTENTIAL TO EMIT OF EXISTING PERMIT UNITS

Potential to Emit Calculations

N-2697-1-3

GENERAL ELECTRIC LM5000 NATURAL GAS FIRED TURBINE ENGINE WITH STEAM INJECTION, SELECTIVE CATALYTIC REDUCTION WITH AMMONIA INJECTION AND AN OXIDATION CATALYST. THE TURBINE POWERS A 49 MW ELECTRICAL GENERATOR. MODIFICATION TO CONVERT THE FUEL USAGE LIMIT TO THE TERMS OF HIGHER HEATING VALUE, REVISE THE EMISSION LIMITS TO CLARIFY THE TIME ALLOWED TO COME INTO COMPLIANCE, REVISE THE EXISTING DAILY EMISSION LIMITS TO THE PRECISION REQUIRED BY DISTRICT POLICY APR-1105 (GUIDELINES FOR THE USE OF SIGNIFICANT FIGURES IN ENGINEERING CALCULATIONS), ADD A SOX EMISSION LIMIT AND ADD A CONDITION REQUIRING THAT ALL RECORDS BE RETAINED FOR AT LEAST FIVE YEARS.

Per project N1062282,

PE = 40,880 lb-NOx/yr
PE = 11,571 lb-SOx/yr
PE = 17,520 lb-PM_{10}/yr
PE = 117,530 lb-CO/yr
PE = 51,830 lb-VOC/yr

N-2697-4-2

240 HP CUMMINS MODEL 6CTA8.3-F1 DIESEL FIRED IC ENGINE WITH A TURBOCHARGER AND AFTERCOOLER SYSTEM POWERING AN EMERGENCY FIRE PUMP

The following Information from project N940387 is used to calculate the potential emissions.

Fuel Use: 11.9 gal/hour

NOx: 6.12 g/bhp-hr
PM: 0.25 g/bhp-hr
CO: 1.45 g/bhp-hr
VOC: 0.46 g/bhp-hr

Assumptions:

- For conservative estimate, all PM is emitted as PM_{10}.

Potential Emissions:

Using Table 2, Page 19 of ATCM, non-emergency use of the in-use stationary emergency IC engine should be 21 to 30 hours/year for diesel PM >0.15 g/bhp-hr and ≤ 0.40 g/bhp-hr.

The diesel PM from the engine is 0.25 g/bhp-hr. Therefore, the engine can be operated up to 30 hours/year. Therefore, emissions during non-emergency use are based on 30 hours/year.

PE = (6.12 g-NOx/bhp-hr)(240 bhp)(30 hr/yr)(lb/453.6g)
= 97 lb-NOx/yr

PE = (11.9 gal/hour)(7.1 lb/gal)(0.0015 lb-S/100 lb-fuel)(2 lb-SO_2/lb-S)(30 hr/yr)
= 0 lb-SO_2/yr

PE = (0.25 g-PM/bhp-hr)(240 bhp)(30 hr/yr)(lb/453.6g)
= 4 lb-PM/yr

PE = (1.45 g-CO/bhp-hr)(240 bhp)(30 hr/yr)(lb/453.6g)
= 23 lb-CO/yr

PE = (0.46 g-VOC/bhp-hr)(240 bhp)(30 hr/yr)(lb/453.6g)
= 7 lb-VOC/yr

ATTACHMENT I
PROPOSED ALTERNATIVE SITING ANALYSIS AND COMPLIANCE CERTIFICATION

SECTION 6.0

Alternatives

The following section discusses alternatives to the Lodi Energy Center (LEC) as proposed in this Application for Certification (AFC). These include the "no project" alternative, power plant site alternatives, linear facility route alternatives, technology alternatives, water supply alternatives, and wastewater disposal alternatives. These alternatives are discussed in relation to the environmental, public policy, and business considerations involved in developing the project. The main objective of the LEC is to produce economical, reliable, and environmentally sound baseload electrical energy for the Northern California Power Agency's (NCPA) project participants.

The Energy Facilities Siting Regulations (Title 20, California Code of Regulations [CCR], Appendix B) guidelines titled *Information Requirements for an Application* require:

> A discussion of the range of reasonable alternatives to the project, including the no project alternative... which would feasibly attain most of the basic objectives of the project but would avoid or substantially lessen any of the significant effects of the project, and an evaluation of the comparative merits of the alternatives.

The regulations also require:

> A discussion of the applicant's site selection criteria, any alternative sites considered for the project and the reasons why the applicant chose the proposed site.

According to the Warren-Alquist Act, evaluation of alternative sites is not required when a natural gas-fired thermal power plant is (1) proposed for development at an existing industrial site, and (2) the project has a strong relationship to the existing industrial site [Public Resource Code 25540.6(b)]. LEC is the type of project that was envisioned by this code section. LEC would be sited on a 4.4-acre parcel sited between the City of Lodi's White Slough Water Pollution Control Facility (WPCF) to the east, treatment and holding ponds associated with the WPCF to the north, the existing NCPA Combustion Turbine Project #2 (STIG plant) to the west, and the San Joaquin County Mosquito and Vector Control facility to the south. The LEC project site is within a 1,040-acre parcel owned by and incorporated into the City of Lodi. LEC will be sharing some infrastructure with the current STIG plant, will tie in to the existing STIG switchyard, and will obtain process water from the WPCF.

Due to these strong relationships, evaluation of alternative sites outside the boundaries of the LEC is not legally required. However, in order to provide some level of information to the CEC Staff and in accordance with pre-filing guidance from CEC Staff, a description of some alternative sites has been provided.

6.1 Project Objectives

The key objective of the LEC is to provide cost-effective and efficient electric generation capacity to NCPA member utilities and the other project participants in the California market. The project site is on the southeast portion of a 1,040-acre parcel annexed by the City of Lodi. The proposed project includes the grading of the existing area and construction of the new facility. As part of this effort, the Applicant has identified the General Electric (GE) Energy Frame 7FA CTG as one of the most efficient generation technologies currently available. The GE 7FA CTG has rapid-response and load-following capability to make it excellent technology to provide electric generation capacity.

The LEC will provide needed electric generation capacity to respond to the demand for electricity by NCPA project participants. The LEC would help to meet identified generation needs. Of equal or greater importance is the LEC's ability to produce electricity more efficiently than other currently generating out-dated power plants, thereby furthering the statewide goals of limiting the environmental effects of power generation.

In addition to technology alternatives, an objective of the site selection was to minimize or eliminate the length of any project linears, including water supply lines, discharge lines, and transmission interconnections. This objective both minimizes potential offsite environmental impacts and cost of construction.

To respond to the need for electric generation capacity for NCPA project participants, NCPA considered several key factors for power plant siting:

- Located within a NCPA project participant's jurisdiction
- Adjacent to or near high-pressure natural gas transmission lines
- Adjacent to or near water supply for cooling purposes to maximize efficiency
- Location near electrical transmission facilities
- Industrial land use designation with consistent zoning
- Site control readily available
- Large enough to accommodate the site including construction laydown
- Located more than 2,500 feet from the nearest residential area
- Potential environmental impacts can be mitigated and minimized

The LEC site meets all of these siting objectives.

The LEC will provide electric generation capacity to the grid to help meet the demand for electricity for project participants by enhancing the reliability of NCPA's electrical system. In addition, as demonstrated by the analyses contained in this AFC, the project would not result in any significant environmental impacts. Therefore, as will be demonstrated below, there are no alternatives that would be preferred over the project as proposed.

6.2 The "No Project" Alternative

If the Applicant were to not build the LEC (the "no project" alternative), it would not be possible to meet the project objectives. The "no project" alternative would forego all of the benefits associated with the LEC project. In addition, if the "no project" alternative was adopted, NCPA would fail to meet its obligations to the participants that are part of its integrated planning unit. NCPA supplies and dispatches the electrical needs to its participants. If the project were not adopted, the participants, to the extent that they are able to do so would purchase capacity and energy from neighboring utilities or generate power on their own. Since power would be generated by others, the emissions and other environmental effects of the proposed project would not be entirely avoided. This would have negative economic consequences for the member cities, commercial and residential rate-payers, and for the regional economy.

In summary, the "no project" alternative would not serve the growing needs of NCPA's participants' businesses and residents for economical, reliable, and environmentally sound generation resources.

6.3 Power Plant Site Alternatives

For comparison purposes, alternative sites were chosen that could feasibly attain most of the project's basic objectives. The alternative sites are shown in Figure 6.3-1. The key siting criteria in considering these alternatives and the proposed LEC site included the following factors:

- Located within a NCPA project participant's jurisdiction
- Location near reliable natural gas supply
- Access to water supply for cooling water
- Location near electrical transmission facilities
- Land zoned for industrial use
- Site control (lease or ownership) feasibility
- A parcel or adjoining parcels of sufficient size for a power plant and construction laydown areas
- Location more than 2,500 feet from the nearest residential areas
- Feasible mitigation of potential environmental impacts

6.3.1 Proposed Lodi Energy Center Site

The proposed site for the LEC at 12751 North Thornton Road, in the City of Lodi, San Joaquin County, meets all of the project's objectives and, in addition, would have no significant, unmitigated, environmental impacts. The proposed site is approximately 4.4 acres. The site is owned by the City of Lodi and has been currently leased by NCPA. The LEC site is:

- Located within the boundaries of the City of Lodi, a project participant for the LEC project.
- Located near the PG&E natural gas supply pipeline #108. Interconnection will require an approximately 2.5-mile-long connection.
- Access to recycled water from the WPCF for cooling through a utility corridor linking the power plant and WPCF.

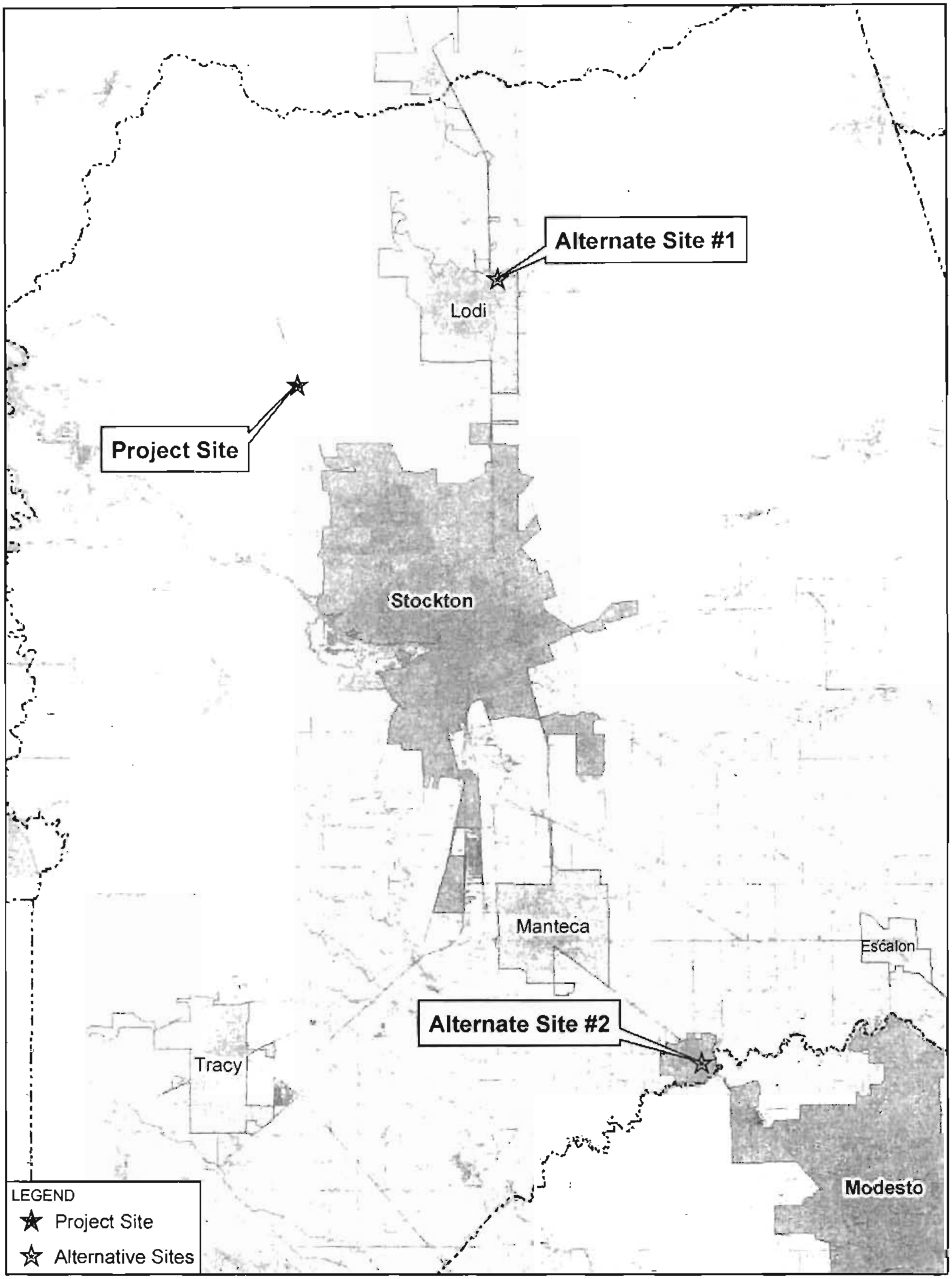
- Located adjacent to the Lodi STIG plant and electrical substation. The project would be able to tie-in to the 230-kV transmission system through the STIG plant's 230-kV switchyard and capacity would serve the need for reliable power.
- Designated as Public zoning with a Utility Facility as an allowable use.
- A signed lease with the City of Lodi for site control.
- Adjacent parcels for construction laydown areas.
- Located more than 2,500 feet from the nearest residential areas.
- Feasible mitigation of potential environmental impacts.
- Construction impacts are minimized to existing residences and businesses.

6.3.2 Alternative 1: East Turner Site

This alternative is approximately 8 miles northeast of the LEC site near the intersection of North Cluff Avenue and East Turner Road. This property is currently an unused vacant lot. The property is zoned M-2, Heavy Industrial and is within the city limits of Lodi, a project participant for the LEC project. The site is surrounded to the north, west, and south by industrial facilities, and to the east by an RV/trailer park. The site would require an approximately 3,200-foot-long natural gas line to tie into a 6-inch, high-pressure, PG&E gas line to the east of the site. In addition a 12-mile-long process water pipeline would need to be constructed to tie this site to the WPCF, and an approximately 1,900-foot-long electrical transmission line would need to be built to an existing PG&E transmission line to the east. A substation would need to be built at this site. This site will also not be adjacent to an existing plant, so shared facilities such as an ammonia tank, administrative buildings, and warehouses will not be available and will need to be built at this site. Shared staff from an adjacent plant are not available, so additional workers will be needed. It is currently unknown whether or not site control would be feasible for NCPA at this location.

6.3.3 Alternative 2: Ripon Site

This alternative is approximately 28 miles southeast of the LEC site in Ripon, California, east of the intersection of South Stockton Avenue and East 4th Street. The site is within a combined service area of both Modesto Irrigation District (MID), as well as PG&E. MID is a project participant for the LEC project. This property is currently undeveloped. This property is zoned M-2, Heavy Industrial and is within the city limits of Ripon. The City of Ripon Wastewater Treatment Plant (Ripon WWTP) is to the south, Highway 99 runs adjacent to the eastern border, and several industrial facilities are to the north and west. The site would require an approximately 1,600-foot-long industrial water supply pipeline to tap into the current pipeline in South Stockton Avenue to the west, and a 3,000-foot-long gas line to tap into a 12-inch-diameter high pressure gas line to the south of the WWTP. This site would require a 500-foot-long electrical transmission line be built to the existing MID Stockton Substation to the west. This site will also not be adjacent to an existing plant, so shared facilities such as an ammonia tank, administrative buildings, and warehouses will not be available and will need to be built at this site. Shared staff from an adjacent plant are also not available, so additional workers will be needed. In addition, it is currently unknown whether or not site control would be feasible for NCPA at this location.



This map was compiled from various scale source data and maps and is intended for use as only an approximate representation of actual locations

0 2.5 5
Miles

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FIGURE 6.3-1
ALTERNATIVE SITE LOCATIONS
LODI ENERGY CENTER
LODI, CALIFORNIA

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CH2MHILL

6.4 Comparative Evaluation of Alternative Sites

In the discussion that follows, the sites are compared in terms of each of the 16 topic areas required in the AFC, as well as in terms of project development constraints. The most useful topics for comparison are as follows:

- **Project Development Constraints**—Are there site characteristics that would prohibit or seriously constrain development, such as significant contamination problems, or lack of fuel, transmission capacity, or water?
- **Land Use Compatibility**—Is the parcel zoned appropriately for industrial use and compatible with local land use policies?
- **Routing and Length of Linear Facilities**—Can linear facilities be routed to the site along existing transmission lines, pipelines, and roads? Will linear facilities be significantly shorter for a given site?
- **Visual Resources**—Are there significant differences between the sites in their potential for impact on valuable or protected viewsheds?
- **Biological Resources**—Would there be significant impacts to wetlands or threatened or endangered species such that mitigation of these effects would be unduly expensive or constrain the supply of available mitigation resources?
- **Contamination**—Is there significant contamination on site, such that cleanup expense would be high or such that cleanup would cause significant schedule delay?
- **Noise**—Is the site sufficiently near a sensitive receptor area such that it would be difficult to mitigate potential noise impacts below the level of significance?
- **Use of Previously Disturbed Areas**—Has the site been previously disturbed? Does the site minimize the need for clearing vegetation and otherwise present low potential for impact on biological and cultural resources?
- **Other Environmental Categories**—Are there significant differences between the sites in their potential for impact in other environmental categories?

There is no precise mathematical weighting system established for considering potential impacts in alternatives analyses. Some of the criteria used to compare the alternatives are more or less important to consider than others. For example, an impact that could affect public health and safety or could result in significant environmental impacts is obviously of greater concern than a purely aesthetic issue associated with an advisory design guideline. It is important in comparing alternatives to focus on the key siting advantages and the potential adverse environmental effects of a particular site. Comparing each of the environmental disciplines and giving each discipline equal weight would provide a misleading analysis because effects in one area are not necessarily equivalent in importance to effects in another area.

For example, although the sites may differ in terms of available local road and street capacities and the current levels of traffic congestion, the number of workers during the operational phase of the project is low and would be unlikely to have a significant effect on local traffic. The sites may differ widely in the amount of traffic congestion they would cause during construction, but this is a temporary impact and should not be a strong consideration in site selection, as long as measures to mitigate this impact are feasible. The sites would not differ significantly in terms of geological hazards, though close proximity to a major fault would call for more rigorous and expensive seismic engineering. Hazardous materials handling and worker health and safety issues would be the same or nearly the same for most sites. Though the risk of a release of hazardous materials during transport might be seen as more or less likely depending on location (roadway hazards, in particular), the record of safe transport and handling of such materials is clear. Further, the sites considered here are all in or near urban areas that are served by good transportation networks and are close to the sources of supply.

Project effects on paleontological and cultural resources are not often consequential in comparing alternatives. Once an initial screening for effects on highly significant sites is completed, the probabilities of encountering hidden paleontological or cultural resources during construction are difficult to calculate or compare.

6.4.1 Project Development Constraints

As indicated in the introductory descriptions of each of the alternative sites, the basic needs of power plant siting for land, access to electrical transmission, gas supply, and water, are met at the LEC site. Both the East Turner site and Ripon site are not near the 230-kV transmission system accessed through the STIG plant's 230-kV switchyard and would require construction of a new transmission line. The LEC site is ideally located in this regard, because fuel gas, process water supply, electrical transmission, and wastewater discharge all have existing onsite tie-ins. The East Turner site would require a 1,900-foot-long electrical transmission line, a 3,200-foot-long natural gas line, and a 12-mile-long process water line. The Ripon site would require a 500-foot electrical transmission line, a 3,000-foot-long natural gas line, and a 1,600-foot-long industrial water supply pipeline.

6.4.2 Air Quality

The quantity of emissions from project operation would be the same at any of the sites. Each of the sites has similar contributions to airsheds and would, therefore, be subject to similar review, offset/mitigation, and permitting requirements. Each site is located in relatively flat terrain that will help to promote dispersion of emissions. The differences between the sites in terms of their distances from the nearest residences should not make a significant difference in air quality impacts at these residences. Since the two alternative sites would require a full operational staff of 21 or 23 employees, versus the addition of only 5 to 7 employees at the proposed site, minor increases of emissions from vehicle traffic could occur if the East Turner or Ripon site were selected. Mitigation would bring any potential impacts to a level below significance for any of the alternatives.

6.4.3 Biological Resources

The LEC site has no biological resources or habitat value. The entire site is either graveled over, or disturbed. The East Turner site is paved, undeveloped land adjacent to industrial facilities and does not appear to be in use and has no biological resources or habitat value.

The Ripon site is undeveloped land adjacent to the Ripon WWTP, and does not appear to be in use. The site has limited biological resources or habitat value.

6.4.4 Cultural Resources

There are no known significant cultural resources at the LEC site. Resources of the East Turner and Ripon sites are unknown. Each of the sites has approximately the same general cultural resource sensitivity.

6.4.5 Geological Resources and Hazards

There would be no significant difference between the sites in terms of geological resources and hazards. There are no geological resources on or near any of the sites.

6.4.6 Hazardous Materials Handling

There would be no significant difference between the site locations in terms of hazardous materials handling. The uses of hazardous materials would be the same for any of the sites. Though there might be differences in the distances that trucks carrying hazardous materials would travel to deliver the materials, these differences would be minor and would not necessarily be consequential, given the effective mitigation measures available and the excellent safety record for transport of these materials.

6.4.7 Land Use and Agriculture

The proposed LEC site is zoned Public, which allows for the use of utilities such as power plants. Both the East Turner and Ripon sites are zoned M-2, Heavy Industrial. The Ripon site is adjacent to the Ripon WWTP, and the MID Modesto Electric Generation Station (MEGS), a peaker power plant.

The proposed LEC site and the Ripon site are designated by the California Department of Conservation as Developed. The East Turner site is designated as Prime Farmland. None of the sites have a Williamson Act Contract (San Joaquin County, 2008).

6.4.8 Noise

Developments at each site would be able to meet the appropriate City and County noise standards. The proposed LEC site is approximately 4,400 feet from the nearest residence, while the East Turner site has a RV/trailer park along the western boundary of the site. The Ripon site is approximately 650 feet to the east (across Highway 99) from the nearest residences.

6.4.9 Paleontology

There would be no significant difference between the sites in terms of potential effects on paleontological resources. The probability of encountering significant fossils is approximately the same at each site.

6.4.10 Public Health

The project would not be likely to cause significant adverse long-term health impacts (either cancer or non-cancer) from exposure to toxic emissions, regardless of the site chosen.

6.4.11 Socioeconomics

All three sites are in San Joaquin County and are within the boundaries of a NCPA LEC project participant. The number of workers, construction costs, and payroll would be nearly the same for the project at each of the sites. The majority of the workers would come from the greater western San Joaquin County area depending on the site. Most workers would commute daily or weekly to the plant site. Some may move temporarily to the local area during construction, causing site-specific impacts to schools, utilities, and emergency services. These impacts would be temporary. Disproportionate impacts to minority and low income populations would be unlikely since minority populations are not concentrated in an area or areas that are also high potential impact areas. The project is not likely to cause significant adverse public health impacts to areas that are disproportionately minority or low income.

6.4.12 Soils and Agriculture

Both the proposed LEC site and East Turner site are within an industrial area that is developed, urban land. The Ripon site is currently undeveloped and appears to be fallow agricultural land; however, it is surrounded by industrial facilities including the Ripon WWTP.

6.4.13 Traffic and Transportation

During operations, the number of employees working at a given time during project operation (21 to 23) will not significantly impact local traffic conditions at any of the sites. However, since the LEC facility will share employees with the STIG facility, only an additional 5 to 7 employees are anticipated at the site, which would not impact local traffic conditions. The peak number of employees during construction (305) will have a larger impact. The impact will be temporary, and can be mitigated by transportation management planning. The effect on construction-phase traffic, therefore, should not figure as a major consideration in evaluating or comparing the sites.

6.4.14 Visual Resources

The proposed LEC site would be visible at a distance from residences in the area; however several existing facilities including the WPCF and STIG facility would block portions of the view. Some structures at the proposed LEC plant would extend above the current structures at the WPCF and STIG facility. Although the LEC would be a large structure, residences are more than 4,400 feet away. Both the East Turner site and the Ripon site would be visible from residences nearby. At the East Turner site, a RV/trailer park is located along the western boundary of the property, and a power plant would be visible. In addition, drivers along East Turner Road and North Cluff Avenue would be able to see the plant as other industrial facilities in the area would provide limited screening.

At the Ripon site the residences on the western side of Stockton Avenue would be partially blocked by the existing warehouses to the west and north of the property. The residents on the east side of Highway 99 however, would have an unobstructed view of the site, as would drivers traveling along Highway 99. The Ripon site is in an area of mixed use, including agricultural, residential, and some industrial, including the Ripon WWTP. In addition, the MEGS peaking power plant is present to the west of the site, within ½ mile of the site.

6.4.15 Water Resources

Two of the sites (LEC and East Turner) would be able to use recycled water for power plant cooling from the City of Lodi. The Ripon site would be able to use the non-potable industrial water system approximately 1,600 feet to the west in South Stockton Avenue which is provided by the City of Ripon for industrial uses. This is consistent with the State Water Resources Control Board's Policy 75-58 indicating that water for power plant cooling should avoid using fresh inland waters if other waters (such as treated wastewater) are available. Water in sufficient quantities is available near all three sites.

6.4.16 Waste Management

The management of wastes would differ slightly between the proposed project site and the two alternatives, though these differences would not necessarily lead to a site preference. Two of the three sites would be vacant at the time NCPA assumes site control, and no demolition would be necessary. The East Turner site might require some demolition and removal of existing concrete, although there is sufficient landfill capacity in the region to handle these wastes.

6.4.17 Summary and Comparison

Based on the site selection criteria as described in Section 6.3, it is clear that power plant siting is feasible at all three sites. Following is a summary of site selection factors:

- **Location with the boundaries of a LEC Project Participant**—Two of the sites are within the boundaries of a LEC Project Participant. Both the LEC and East Turner sites are with the City of Lodi boundaries. The Ripon site is in the jurisdiction of both MID and PG&E, and may not be considered completely within the jurisdiction of a project participant.
- **Location near ample natural gas supply**—Each of the sites are near a sufficient source of fuel gas. There are high pressure gas lines within the vicinity of all three sites; however a gas line to each of the sites would need to be constructed. The LEC site will require a 2.5-mile-long gas line to be constructed to PG&E natural gas line #108. The East Turner site would require an approximately 3,200-foot-long gas line to be constructed to a 6-inch-diameter PG&E natural gas line to the east and the Ripon site would require an approximately 3,000-foot-long gas line to be constructed to a 12-inch-diameter PG&E natural gas line to the south of the Ripon WWTP.
- **Location near a sufficient source of cooling water, preferably treated wastewater**—Each of the sites are near a sufficient source of water for use of process water. The LEC site will connect via a short connection to the WPCF to the east. The East Turner site would require a 12-mile-long connection to the WPCF. The Ripon site would require an approximately 1,600-foot-long connection to the industrial wastewater supply pipeline in South Stockton Avenue.
- **Location near electrical transmission facilities**—The LEC site will connect to the existing STIG switchyard which ties into PG&E's 230-kV transmission line to the west of

the STIG facility. A 1,900-foot-long transmission line would need to be constructed to connect the East Turner to the PG&E transmission line to the east, and would require construction of a new substation. A 500-foot-long transmission line would be required to connect the Ripon site to the Stockton substation.

- **Land zoned for industrial use**—The LEC site is zoned Public, which allows for the use of public facilities including utilities. The East Turner site and the Ripon site are zoned M-2, Heavy Industrial.
- **Site control feasible**—Site control is feasible at the LEC site. It is unknown whether or not the East Turner site or Ripon site are available for lease or purchase. Therefore, site control feasibility for these sites is undetermined.
- **Parcel or adjoining parcels of sufficient size for a power plant**—There is sufficient land available at each parcel to develop a power plant.
- **Location more than 2,500 feet from the nearest residential areas**—The LEC site is approximately 4,400 feet from the nearest residence. The East Turner site is adjacent to a RV/trailer park to the west, approximately 50 feet from the property boundary. The nearest residence to the Ripon site is approximately 650 feet to the east, on the other side of Highway 99.
- **Mitigation of potential impacts feasible**—Mitigation of potentially significant environmental impacts appears feasible at all three sites.

In conclusion, the LEC site offers some project design advantages over the both the East Turner and Ripon sites. The site is adjacent to an existing process water supply source from the WPCF, is located in an industrial zoned pocket within a predominantly agricultural area, and will be adjacent to an existing power plant, which offers the ability to share staff and facilities between the two plants, including the STIG switchyard. In addition, the nearest resident is approximately 4,400 feet away.

The East Turner site would require a 1,900-foot-long interconnection to the nearest PG&E transmission line, and would require the construction of a substation. Process water for the East Turner site would require a 12-mile-long pipeline to the WPCF. In addition, the site is approximately 50 feet away from the nearest residence. The East Turner site is designated as Prime Farmland and may require some mitigation. In addition, it is unknown if the East Turner site is available for long-term lease or purchase.

The Ripon site would connect to the Stockton substation and would require only a 500-foot-long transmission line. In addition similar to the LEC site, the Ripon site could tie in directly to a nearby water source, the City of Ripon industrial water supply. Since this site appears to be relatively undisturbed and located on ruderal land, the site may have some limited plant and wildlife habitat. In addition, it is unknown if the Ripon site is available for long-term lease or purchase.

Taken all together, the LEC site best meets the project objectives without resulting in any adverse environmental impacts as compared to the East Turner and Ripon sites. As a result, the East Turner and Ripon sites were rejected in favor of the LEC site. Table 6.4-1 lists the environmental and project development constraints of the LEC and alternative sites.

TABLE 6.4-1
Environmental and Project Development Constraints of the LEC and Alternative Sites

Site or Alternative	LEC Site	East Turner	Ripon
Site control	Yes	No	No
Land Use and zoning	Zoned as Public – power plants are an allowable use	Zoned as M-2, Heavy Industrial	Zoned as M-2, Heavy Industrial
California Department of Conservation Designation	Developed	100% Prime Farmland	Developed
Williamson Act Contract	No	No	No
Sensitive noise receptors nearby	Few nearby residences (nearest approx. 4,400 feet to the northeast)	RV/trailer park on western boundary of site	Nearest residence approximately 650 feet to the east on the east side of Highway 99
Visual Resources	WPCF to the east of the proposed site, and STIG plant to the west of the proposed site. Both facilities will block views for residents to the east and west, but not to viewers traveling along I-5. Limited residences in surrounding area	Several industrial facilities in nearby vicinity to the north east and south. RV/trailer park adjacent to property on the west. Facility would be visible from both East Turner Road and Cluff Avenue	One existing peaking power plant within ½ mile of proposed site. Some industrial activities present in area, including the Ripon WWTP
Biological Resources	Land has been used as a laydown area for multiple WPCF expansion projects. Limited habitat available for wildlife and ground nesting birds.	Site is currently paved. No habitat available for wildlife and ground nesting birds.	Site has not been farmed, and is currently ruderal vegetation. Habitat is available for wildlife and ground nesting birds.
Cultural Resources	No	Unknown	Unknown
Significant unmitigated impacts or costly mitigation?	No	Site is on Prime Farmland, and may require some mitigation. A long pipeline would be needed to supply recycled water.	No.

6.5 Alternative Project Design Features

The following section addresses alternatives to some of the LEC design features, such as the locations of the natural gas supply pipeline, electrical transmission line, and water supply pipeline.

6.5.1 Alternative Natural Gas Supply Pipeline Routes

The preferred natural gas pipeline route would be adjacent to the existing 2.5-mile pipeline for the STIG Plant which is adjacent to the proposed LEC site. The existing gas pipeline exits the STIG plant approximately 400 ft to the south of the White Sough metering station and then turns east along the access road to the WPCF and under Interstate 5 (I-5). The pipeline continues east from I-5, along a utility easement, bordering several private agricultural fields until the intersection of De Vries Road and Armstrong Road. The pipeline then continues in an easement adjacent to the north side Armstrong Road to PG&E's high pressure natural gas pipeline #108. Due to the presence of the existing 2.5-mile gas pipeline, no other alternatives were analyzed.

6.5.2 Electrical Transmission System Alternatives

The preferred transmission route would be to link the LEC site to the power grid through the existing STIG plant's 230-kV switchyard substation by a three-phase 230-kV transmission circuit. The proposed 230-kV route will exit the project site at the northwest corner and will extend along the northern border of the STIG plant before turning south along the eastern boundary of the STIG plant and continuing to the existing 230-kV switchyard. From the switchyard, the line will tie into the PG&E 230 kV transmission corridor. Due to the presence of the existing electrical switchyard adjacent to the LEC site, no other alternatives were analyzed.

6.5.3 Water Supply Alternatives

The LEC project will connect with the WPCF for supplies of recycled water for cooling through a utility corridor linking the power plant and WPCF. Other sources of cooling water might include potable water from an onsite well used to supply potable water to LEC, or the potable water from the WPCF onsite well. Reclaimed water is clearly the better alternative because it provides for beneficial use for treated wastewater which might otherwise be wasted. Using potable water from the onsite well would involve consuming large quantities of scarce fresh water for power plant cooling that could be more beneficially used for other purposes.

6.6 Technology Alternatives

The configuration of the LEC was selected from a wide array of technology alternatives. These include generation technology alternatives, fuel technology alternatives, combustion turbine alternatives, NO_x control alternatives.

6.6.1 Generation Technology Alternatives

Selection of the power generation technology focused on those technologies that can utilize the natural gas readily available from the existing transmission system. Following is a discussion of the suitability of such technologies for application to the LEC.

6.6.1.1 Conventional Boiler and Steam Turbine

This technology burns fuel in the furnace of a conventional boiler to create steam. The steam is used to drive a steam turbine-generator, and the steam is then condensed and returned to the boiler. This is an outdated technology that is able to achieve thermal efficiencies up to approximately 36 percent when utilizing natural gas, although efficiencies are somewhat higher when utilizing oil or coal. Because of this low efficiency and large space requirement, the conventional boiler and steam turbine technology was eliminated from consideration.

6.6.1.2 Conventional Simple-Cycle Combustion Turbine

Conventional aero-derivative turbine-generator units are able to achieve thermal efficiencies up to approximately 38 percent. A simple-cycle combustion turbine has a quick startup capability and lower capital cost than that of a combined-cycle, and is very appropriate for peaking applications. Because of its relatively low efficiency, conventional simple-cycle technology tends to emit more air pollutants per kilowatt-hour. Because of this relatively low efficiency, the conventional simple-cycle combustion turbine technology was eliminated from consideration.

6.6.1.3 Kalina Combined-Cycle

This technology is similar to the conventional combined-cycle, except a mixture of ammonia and water is used in place of pure water in the steam cycle. The Kalina cycle could potentially increase combined-cycle thermal efficiencies by several percentage points. This technology is still in the development phase and has not been commercially demonstrated; therefore, it was eliminated from consideration.

6.6.1.4 Internal Combustion Engines

Internal combustion engine designs are also available for small peaking power plant configurations. These are based on the design for large marine diesel engines, fitted to burn natural gas. Advantages of internal combustion engines are as that they: (1) use very little water for cooling, because they use a closed-loop coolant system with radiators and fans; (2) provide quick-start capability (on-line at full power in 10 minutes) and (3) are responsive to load-following needs because they are deployed in small units (for example, 10 to 14 engines in one power plant), that can be started up and shut down at will. Disadvantages of this design include somewhat higher emissions than comparable combustion turbine technology. In addition, internal combustion engine installations are generally deployed at less than 150 MW, and so would not meet one of the project objectives, which is for 255 MW of peaking power.

6.6.2 Fuel Technology Alternatives

Technologies based on fuels other than natural gas were eliminated from consideration because they do not meet the project objective of utilizing natural gas available from the existing transmission system. Additional factors rendering alternative fuel technologies unsuitable for the proposed project are as follows:

- No geothermal or hydroelectric resources exist in San Joaquin County.
- Biomass fuels such as wood waste are not locally available in sufficient quantities to make them a practical alternative fuel and LEC site space is limited.
- Solar and wind technologies are generally not dispatchable and are, therefore, not capable of producing ancillary services other than reactive power, and LEC site space is limited.
- Coal and oil technologies emit more air pollutants than technologies utilizing natural gas.

The availability of the natural gas resource provided by PG&E, as well as the environmental and operational advantages of natural gas technologies, make natural gas the logical choice for the proposed project.

6.6.3 NO_x Control Alternatives

To minimize NO_x emissions from the LEC, the combustion turbine generators (CTGs) will be equipped with water injection combustors and selective catalytic reduction (SCR) using anhydrous ammonia as the reducing agent. The following combustion turbine NO_x control alternatives were considered:

- Steam injection (capable of 25 to 42 parts per million [ppm] NO_x)
- Water injection (capable of 25 to 42 ppm NO_x)
- Dry low NO_x combustors (capable of 15 to 25 ppm NO_x)

Water injection or dry low NO_x were selected because these allow for lower acceptable NO_x emissions while being able to achieve an output turndown rate of 30 percent. This turndown is necessary to meet variable load demand.

Two post-combustion NO_x control alternatives were considered:

- SCR
- EMx™ (formerly SCONO$_x$™)

SCR is a proven technology and is used frequently in combined-cycle applications. Ammonia is injected into the exhaust gas upstream of a catalyst. The ammonia reacts with NO_x in the presence of the catalyst to form nitrogen and water.

EM$_x$™ consists of an oxidation catalyst, which oxidizes carbon monoxide to carbon dioxide and nitric oxide to nitrogen dioxide. The nitrogen dioxide is adsorbed onto the catalyst, and the catalyst is periodically regenerated.

The level of emission control effectiveness between the EM$_x$ and SCR technologies are approximately the same. However, the EM$_x$ technology does not employ the use of ammonia to reduce air emissions. The CEC recently summarized in the EPA's opinion (Colusa Generating Station Final Staff Assessment) "that EM$_x$ is no more effective for reducing air quality impacts than selective catalytic reduction (or "SCR", which is what is proposed for CGS), and it also found EM$_x$ to be significantly more expensive and arguably less reliable, particularly for larger facilities." Therefore, EM$_x$ was not considered for the LEC project.

The following reducing agent alternatives were considered for use with the SCR system:

- Anhydrous ammonia
- Aqueous ammonia
- Urea

Anhydrous ammonia is used in many combined-cycle facilities for NO_x control, but is more hazardous than diluted forms of ammonia; however, because the anhydrous ammonia tank will be shared between the LEC and STIG facility, aqueous ammonia use was not investigated for this site. Urea has not been commercially demonstrated for long-term use with SCR and was eliminated from consideration.

6.7 References

San Joaquin County. 2008. http://sjmap.org/mapapps.asp (Accessed on July 24, 2008).

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September 26, 2008

Mr. Jagmeet Kahlon
San Joaquin Valley Air Pollution
Control District
4800 Enterprise Way
Modesto CA 95356-8718

Subject: Compliance Statement for the NCPA Lodi Energy Center

Dear Mr. Kahlon:

In accordance with Rule 2201, Section 4.15, "Additional Requirements for New Major Sources and Federal Major Modifications," NCPA is pleased to provide this compliance statement regarding its proposed Lodi Energy Center project.

All major stationary sources in California owned or operated by NCPA, or by any entity controlling, controlled by, or under common control with NCPA, and which are subject to emission limitations, are in compliance or on a schedule for compliance with all applicable emission limitations and standards. These sources include one or more of the following facilities:

Lodi Combustion Turbine No. 2
Lodi Peaking Turbines
Alameda Peaking Turbines
Roseville Combustion Turbine

Based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

Please contact me if you have any questions regarding this certification.

Sincerely,

9/26

Ed Warner
Project Manager, Lodi Energy Center
Northern California Power Agency

cc: Jeffrey Adkins, Sierra Research
Sarah Madams, CH2M Hill
Andrea Grenier, Grenier & Associates, Inc.
Susan Strachan, Strachan Consulting
Scott Galati, Galati-Blek LLP
Robert Worl, CEC

San Joaquin Valley
Unified Air Pollution Control District

TITLE V MODIFICATION - COMPLIANCE CERTIFICATION FORM

I. TYPE OF PERMIT ACTION (Check appropriate box)

[✓] SIGNIFICANT PERMIT MODIFICATION
[ ] MINOR PERMIT MODIFICATION
[ ] ADMINISTRATIVE AMENDMENT

COMPANY NAME: Northern California Power Agency	FACILITY ID: N – 2697
1. Type of Organization: [ ] Corporation [ ] Sole Ownership [ ] Government [ ] Partnership [✓] Utility	
2. Owner's Name: Northern California Power Agency	
3. Agent to the Owner: Ed Warner	

II. COMPLIANCE CERTIFICATION (Read each statement carefully and initial all circles for confirmation):

✓ Based on information and belief formed after reasonable inquiry, the equipment identified in this application will continue to comply with the applicable federal requirement(s).

✓ Based on information and belief formed after reasonable inquiry, the equipment identified in this application will comply with applicable federal requirement(s) that will become effective during the permit term, on a timely basis.

✓ Corrected information will be provided to the District when I become aware that incorrect or incomplete information has been submitted.

✓ Based on information and belief formed after reasonable inquiry, information and statements in the submitted application package, including all accompanying reports, and required certifications are true accurate and complete.

I declare, under penalty of perjury under the laws of the state of California, that the forgoing is correct and true:

[signature] 9/3/08

Signature of Responsible Official Date

Ed Warner

Name of Responsible Official (please print)

Project Manager, Lodi Energy Center

Title of Responsible Official (please print)